PETROLEUM DEVELOPMENT AND TECHNOLOGY

1948

PETROLEUM DIVISION

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Volume 174

PETROLEUM DEVELOPMENT AND TECHNOLOGY 1948

PETROLEUM DIVISION

PAPERS AND DISCUSSIONS PRESENTED BEFORE THE DIVISION AT MEETINGS HELD AT GALVESTON, OCT. 3–5, 1946; LOS ANGELES, OCT. 24–25, 1946, OCT. 23–24, 1947; NEW YORK, MARCH 19–22, 1947; DENVER, SEPT. 28–OCT. 2, 1947; AND TULSA, OCT 8–10, 1947.

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FOREWORD

It becomes more apparent as years pass that the Petroleum Division is performing an indispensable function in the scientific development of the petroleum industry. Even in the absence of some of the qualities possessed by older institutions, it is hoped that the Division will at all times provide a forum broad enough to meet the affairs of our times and so help to abate the concern which may be felt at the rapid tendency toward engineering specialization.

Among the notable achievements for 1947 were a general intensification and extension of Division activities, as witnessed by formation of new Sections in Venezuela and Oklahoma City, a rapid membership increase, and record attendance at Division and Local Section meetings. Most gratifying is the success of student associate meetings and the interest displayed by the younger members.

A highlight of an extra-curricula nature was submission of the Division's "Plan for Expansion of Petroleum Technology," culminating in the Johnson Report formally presented at the February meeting of the Board of Directors. Successful implementation of this program, we feel, will result in national benefits to the Institute. In line with this development, and presuming its furtherance, active plans are being made to greatly improve the publications of the Division.

At the 76th Annual Meeting, held in New York, Wallace Everette Pratt was awarded the Anthony F. Lucas Medal. His picture and the citation appear elsewhere in this volume. E. Charles Patton, Jr., of Dallas, was the recipient of the Rossiter W. Raymond Award. Another notable feature of the Annual Meeting was the presentation for the first time of the Division's "Certificate of Service" in acknowledgment of exceptional services of members to the Division. Recipients were Eugene A. Stephenson, and (posthumously) Fred B. Plummer and Earl Oliver.

Recognition of recent past attainments of the Division is due our past Chairman, Howard C. Pyle, the many members who have served on committees, the authors who have made the valuable contributions contained in this volume and to be contained in subsequent volumes, and to the staff of the Division's office. The Division wishes to take this opportunity to express its appreciation of the careful consideration and cooperation of the Institute's Board of Directors and New York headquarters personnel.

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THE ANTHONY F. LUCAS FUND AND MEDAL

In 1936 the Institute established the Anthony F. Lucas Gold Medal, to be awarded from time to time "for distinguished achievement in improving the technique and practice of finding and producing petroleum." These awards are sponsored by the Petroleum Division.

Captain Lucas was a pioneer in the oil industry, one of the early wildcatters and a leading mining and petroleum engineer. He was famous as the discoverer of Spindletop. He became a member of the Institute in 1895 and in 1913 was the first Chairman of the Petroleum and Gas Committee of the Institute, the forerunner of the present Petroleum Division. He also headed the Committee in 1914, 1917 and 1918.

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"For his broad vision and leadership in evaluating for industry the application of geology, geophysics and engineering to finding, developing and producing petroleum; for his success in inspiring others to broaden the use of science in the business of providing petroleum to the world."

Phase Behavior in the Methane-ethane-n-pentane System

By G. W. Billman,* B. H. Sage,* Member AIME and W. N. Lacey*

(New York Meeting, March 1947)

Abstract

The composition of the coexisting phases in the methane-ethane-n-pentane system was determined at 100°F. This was accomplished by withdrawing samples of the coexisting phases under isobaric-isothermal conditions. The relative amount of each of the components present in the liquid and gas phases was determined by conventional analytical fractionation methods. The phase behavior of this system approximates that estimated from generalized correlations which take into account the influence of the nature and amount of each of the components present upon the equilibrium. It was found that for particular pressures and temperatures the equilibrium constant of each of the components was influenced significantly by the composition of the system and this effect was more pronounced at the lower pressures for methane than for the components of greater molecular weight. However, at the higher pressures approaching the maximum two-phase pressure for the system at this temperature the composition markedly influences the equilibrium constants of all the components at a particular pressure and temperature. The results of this study are presented in graphical and tabular form.

Introduction

The phase behavior of many of the binary systems containing paraffin hydrocarbon components from methane through n-pentane has been investigated during recent years. In addition the compositions of the coexisting phases in mixtures of crude oil and natural gas have been studied.[1] However, these results do not establish the influence of the nature and amount of the other substances making up a multicomponent system upon the gas-liquid equilibrium constant of any one component. A preliminary correlation on the basis of values for binary systems was made[2] utilizing such experimental information as was available. However, there is need for much additional information regarding behavior in systems containing more than two components.

Study of the phase behavior of ternary systems offers a feasible attack upon the determination of the influence of composition as well as of pressure and temperature upon the several equilibrium constants concerned. An investigation of the phase behavior of the methane-propane-n-pentane system at 100°, 160°, and 220°F was reported.[3,4] This work served to illustrate the marked influence of concentration of the other components upon the equilibrium constants. Variations of as much as 50 pct in the equilibrium constants for methane for fixed temperature and pressure were observed in regions remote from the critical state. Likewise there was a marked variation in the equilibrium constants of propane and n-pentane as a result of changes in the composition. These results indicated the desirability of investigating additional ternary systems. The present paper deals with a study of the methane-ethane-n-pentane system at 100°F, which is similar in many respects to the work upon the methane-propane-n-pentane system cited above.

Manuscript received at the office of the Institute Feb. 10, 1947. Issued as TP 2232 in Petroleum Technology, July 1947.

* California Institute of Technology, Pasadena, California.

[1] References are at the end of the paper.

Method

The compositions of the phases coexisting under isobaric-isothermal conditions were established by withdrawing samples of the gas and liquid phases which had been brought to thermodynamic equilibrium by prolonged mechanical agitation. The sample was confined in a steel vessel over mercury, the pressure being controlled by the addition or withdrawal of the latter fluid. After equilibrium had been reached, isobaric-isothermal conditions were maintained during the withdrawal of the samples by controlled addition of mercury to the equilibrium vessel. In general the withdrawals were accomplished with deviations from isobaric conditions of less than 3 psi. Mechanical agitation was discontinued during the withdrawal process and it is believed that the divergences from the original equilibrium state as a result of slight changes of pressure did not cause significant error in the experimental results.

The temperature of the equilibrium cell was kept at desired values by immersing it in an agitated oil bath, thermostatically controlled by use of suitable electronic circuits to give variations of less than 0.3°F with respect both to time and location within the bath. Temperatures were related to the International Platinum Scale by a mercury-in-glass thermometer which had been compared with the temperature indications of a standardized, strain-free platinum resistance thermometer. It is believed that the temperature of the equilibrium mixture was known within 0.2°F.

The pressure during the approach to equilibrium and during the withdrawal of the samples was measured by means of a commercial type of piston-and-cylinder pressure balance with an estimated uncertainty of 2 psi or less. This instrument was calibrated against a precision pressure balance[8] which in turn had been calibrated against the known vapor pressure of carbon dioxide. The equipment was essentially the same as that used in earlier studies.[3,4,8]

The fractionating columns employed in the determination of the composition of gas and liquid phase samples had internal diameters of 0.12 and 0.18 in. and lengths of 4 and 5 ft, respectively. The analyses were carried out in conventional fashion except that in the transition region between one component and another the distillation was repeated in order to check the completeness of separation of the component being withdrawn. Comparison of duplicate samples indicates that the overall analytical uncertainty in the mol fraction of a component was approximately 0.002, while a precision of 0.001 was usually easily obtainable.

At low pressures it is possible that very small amounts of liquid phase on the walls of the equilibrium chamber near the sample outlet were carried out when a sample of the gas phase was withdrawn. At higher pressures this difficulty was less probable. After considering these somewhat intangible quantities in addition to the uncertainties in pressure, temperature, and composition it appears that, when a component was present only in small quantity, the uncertainty in mol fraction is probably less than 0.005.

Materials

The methane used in this investigation was obtained from the Buttonwillow field in California. As received, the sample was saturated with water and contained approximately 0.003 mol fraction carbon dioxide and 0.0004 mol fraction heavier hydrocarbon. Combustion analyses have indicated that nitrogen and other noncombustible materials are present in this gas in negligible amounts. Before use, the methane was dried and purified by passing it at a pressure of 300 psi or more through layers of calcium chloride, potassium hydroxide, activated charcoal, and ascarite. The partially purified methane was then

passed through a copper coil immersed in a mixture of acetone and solid carbon dioxide.

The ethane was procured from the Carbide and Carbon Chemicals Corporation and when received it contained substantial amounts both of more and less volatile components. This crude ethane was purified by repeated low temperature fractionation in which the first and last tenths of the overhead product were discarded. Analytical measurements upon the purified material indicated that it did not contain more than 0.002 mol fraction of material other than ethane.

The n-pentane was obtained from the Phillips Petroleum Company whose special analysis upon a similar sample indicated the material to contain approximately 0.005 mol fraction isopentane and less than 0.001 mol fraction of other hydrocarbon impurities. Care was exercised to avoid contamination of the sample with air and a further precaution was taken by submitting the n-pentane to prolonged boiling after addition to the equilibrium apparatus. Addition of the material to the equilibrium chamber was accomplished in substantially the same way as was described for the methane-propane-n-pentane system.[3,4,6]

Experimental Results

The equilibrium states were at pressures of 500, 1000, 1500, and 2000 psi.[a] The compositions of the coexisting phases are reported in terms of mol fraction in Table 1. At two states the system was homogeneous and so the compositions of the two samples taken from the upper and lower part of the equilibrium equipment are the same within the uncertainty of measurement.

The compositions of the coexisting phases for each of the experimentally studied pressures are shown in Figs 1 to 4, inclusive. In each figure the compositions of the coexisting phases for the experimentally studied mixtures have been connected by dotted lines. For the purpose of systematic portrayal of the behavior of the system, solid combining lines are shown for even values of a parameter C which is defined by Eq 1.[3]

$$C = \frac{X_2}{(X_2 + X_5)} \qquad [1]$$

In this equation, X_2 and X_5 represent the mol fractions of ethane and n-pentane, respectively, in the mixture.

Table 1—*Experimentally Determined Compositions of Coexisting Phases*

Pressure, Psi	Gas Phase,			Liquid Phase,		
	Methane	Ethane	n-Pentane	Methane	Ethane	n-Pentane
	100°F					
500	0.904[a]	0.0377	0.0583	0.154	0.0284	0.818
	0.652	0.297	0.0519	0.115	0.223	0.662
	0.517	0.431	0.0511	0.0947	0.327	0.578
	0.275	0.681	0.0440	0.0550	0.514	0.431
	0.000	0.965	0.0349	0.0000	0.736	0.264
1,000	0.762	0.188	0.0499	0.263	0.211	0.526
	0.674	0.282	0.0454	0.246	0.314	0.440
	0.596	0.360	0.0443	0.237	0.396	0.368
	0.548	0.405	0.0468	0.224	0.444	0.331
	0.483	0.473	0.0438	0.214	0.515	0.271
	0.394	0.562	0.0441	0.198	0.602	0.200
	0.196[b]	0.758[b]	0.0450[b]	0.196[b]	0.759[b]	0.0451[b]
1,500	0.814	0.125	0.0608	0.420	0.152	0.428
	0.689	0.244	0.0670	0.412	0.291	0.297
	0.588	0.334	0.0779	0.413	0.378	0.209
	0.461[b]	0.443[b]	0.0953[b]	0.462[b]	0.443[b]	0.0948[b]
2,000	0.899	0.0173	0.0833	0.580	0.0217	0.399
	0.801	0.0981	0.101	0.587	0.116	0.297
	0.763	0.121	0.116	0.599	0.140	0.261

[a] Compositions are expressed as mol fraction.
[b] Single phase present.

As an aid in visualizing the interrelation of pressure and composition with the phase behavior of the system an equilateral projection of a pressure-composition figure of the methane-ethane-n-pentane system at 100°F is presented in Fig 5. Values for the vapor pressure of pentane were taken from published data,[3,8] as was the information for the methane-n-pentane system.[8] These measurements were carried out primarily by the determination of the volumetric behavior of individual mixtures of methane and n-pentane. Values for

[a] Throughout this paper pressure is expressed in pounds per square inch absolute.

the ethane-n-pentane system were not available and those given were determined by extrapolating the equilibrium constants determined for the ternary system to compositions corresponding to varying mixtures of ethane and n-pentane. The data are not believed to be more than qualitatively indicative of the behavior of the ethane-n-pentane system.

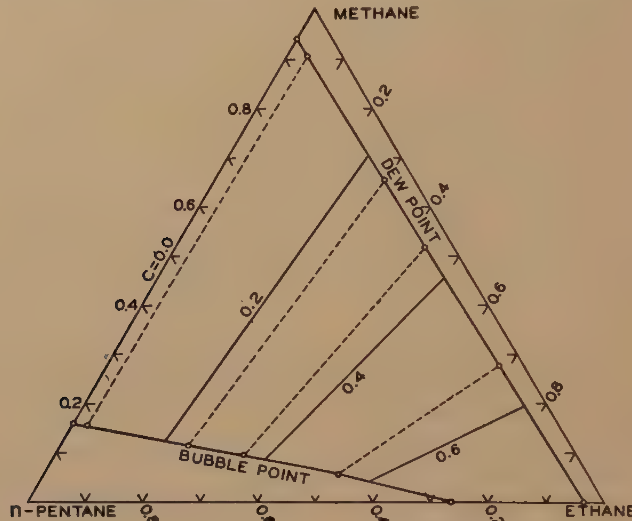

Fig 1—Molal composition diagram at 500 psi and 100°F.

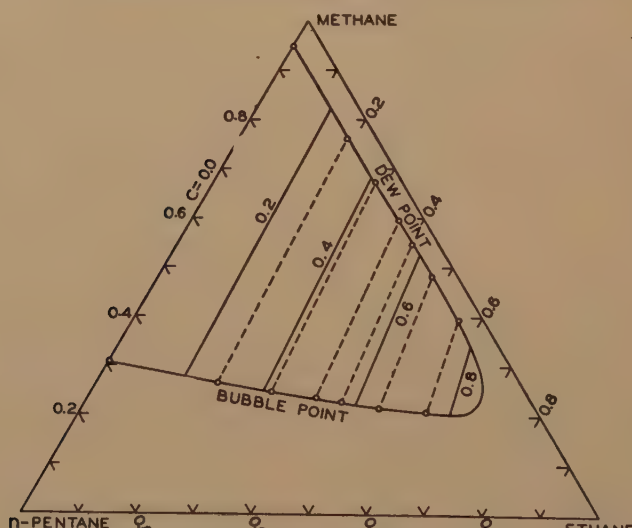

Fig 2—Molal composition diagram at 1000 psi and 100°F.

The behavior of the system at 500 psi is shown by the boundary curve BMOKE and it is apparent that two phases are obtainable within limited ranges of composition in both the methane-pentane and the ethane-pentane systems, but only a single gaseous phase exists at 100°F for the methane-ethane system at any pressure. Combining lines for several

values of the parameter C are shown in this diagram, corresponding to the behavior shown in Fig 1. Similarly, the behavior of this system at 1500 psi is shown by the boundary CHID for which combining lines are shown for several values of the parameter C. Corresponding curves are shown for 1000 and 2000 psi.

The locus of critical states from N to T has been indicated in the figure and the maximum critical pressure for this system at 100°F appears to occur in the binary methane-n-pentane system. In other words, there is no maximum in the critical pressure locus for ternary mixtures lying between the critical state of the methane-n-pentane

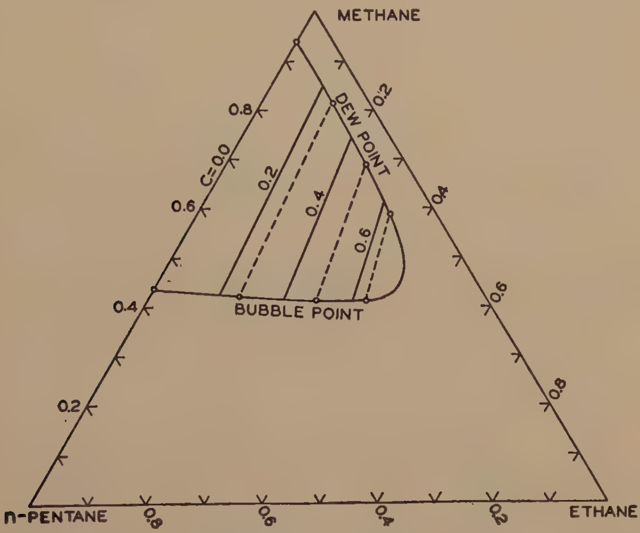

FIG 3—MOLAL COMPOSITION DIAGRAM AT 1500 PSI AND 100°F.

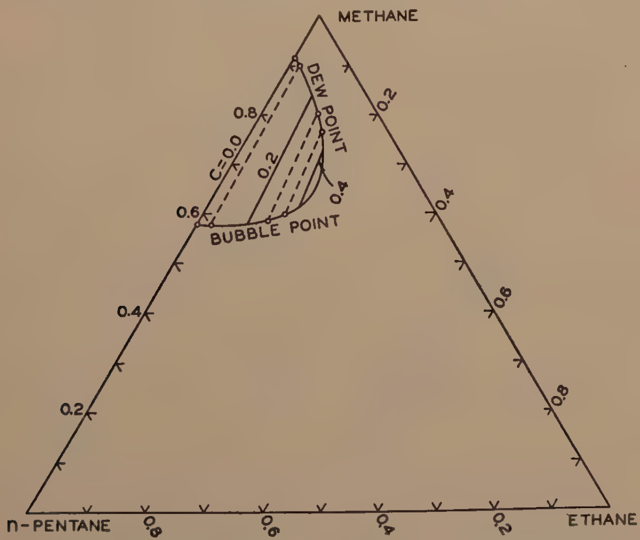

FIG 4—MOLAL COMPOSITION DIAGRAM AT 2000 PSI AND 100°F.

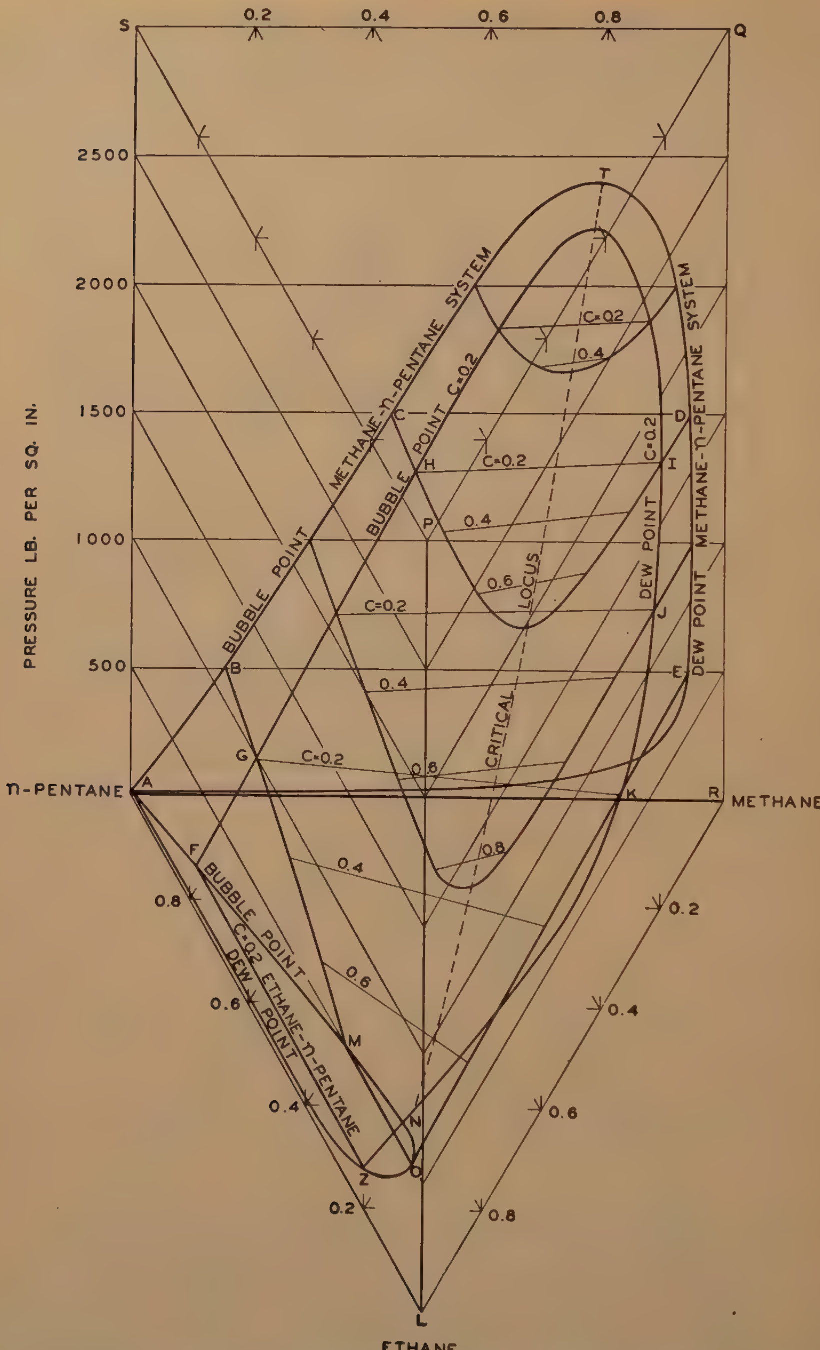

Fig 5—Molal composition-pressure diagram for ternary system at 100°F.

system and that of the ethane-n-pentane system.

By way of illustration, the locus of coexisting phases corresponding to a value of the parameter C of 0.2 has been indicated. This curve FGHIJKZ is generated by the intersection of combining lines with the corresponding bubble-point and dew-point surfaces of Fig 5.

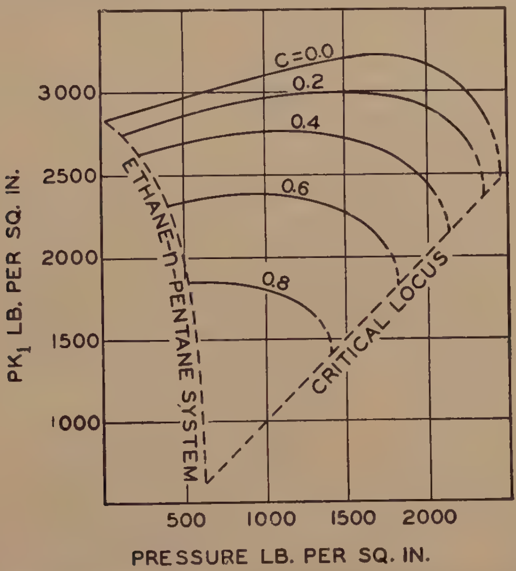

Fig 6—Equilibrium constants for methane in methane-ethane-n-pentane system at 100°F.

Gas-liquid Equilibrium Constants

The ratio of the mol fraction of a component in the gas phase to its mol fraction in the coexisting liquid phase has been called an equilibrium constant. Such ratios are actually a function of the state of a heterogeneous system and vary with the pressure, temperature, and the nature and amount of each of the components present. Under certain conditions a number of the hydrocarbons form substantially ideal solutions and under these conditions the equilibrium constant is primarily a function of pressure and temperature. However, in the present system the deviation from such simplification is large and the equilibrium constant must be considered to be a function of pressure, temperature, and the composition of the system. From the data recorded in Table 1 the equilibrium constants were computed and, after graphical smoothing with respect to the parameter C, the results were plotted in relation to the equilibrium pressure as shown in Figs 6, 7, and 8 for methane, ethane, and n-pentane, respectively.

In the case of Fig 6 the product of pressure and the equilibrium constant has been shown as the dependent variable in order to increase the graphical precision with which the data may be presented. In each of these figures, curves end at low pressure at values for the ethane-n-pentane system, and at higher pressure at the critical states for the ternary system.

It is often of interest to establish the limiting value of the equilibrium constant of one of the more volatile components as its concentration approaches zero. For example, if it is desired to determine the limiting value of the equilibrium constant of methane in the methane-ethane-n-pentane system as the pressure is decreased

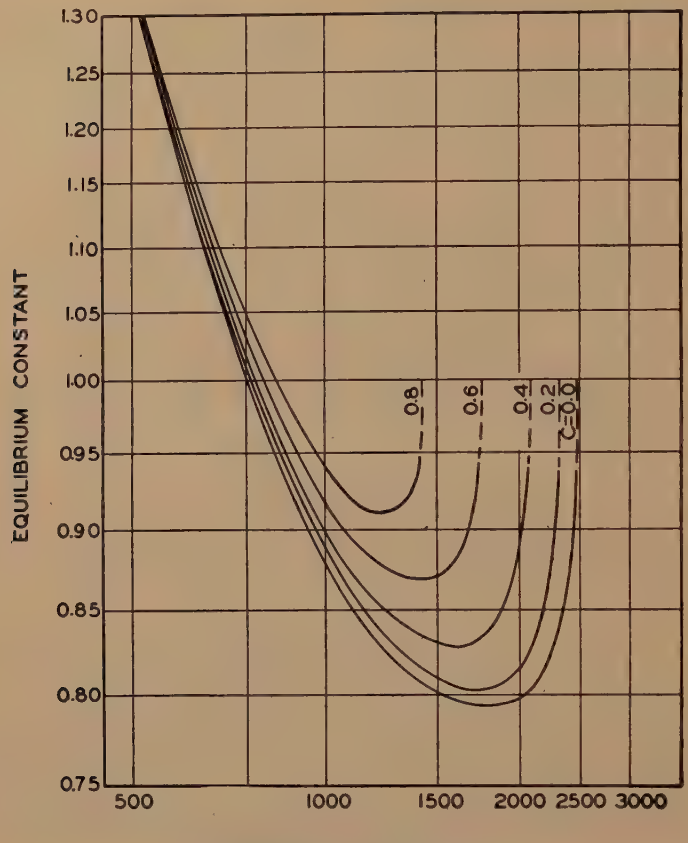

FIG 7—EQUILIBRIUM CONSTANTS FOR ETHANE IN METHANE-ETHANE-N-PENTANE SYSTEM AT 100°F

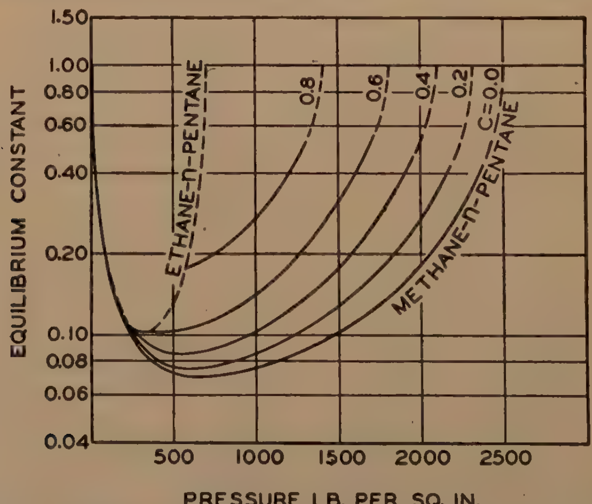

FIG 8—EQUILIBRIUM CONSTANTS FOR N-PENTANE IN METHANE-ETHANE-N-PENTANE SYSTEM AT 100°F.

to the two-phase pressure of the ethane-n-pentane system this may be accomplished as will be described.

ment with values obtained by extrapolation of the data to the two-phase pressure of the ethane-n-pentane system.

TABLE 2—*Equilibrium Constants for Components of Methane-ethane-n-pentane System*

Pressure, Psia	C	Equilibrium Constants			Composition, Gas Phase			Composition, Liquid Phase		
		Methane	Ethane	n-Pentane	Methane	Ethane	n-Pentane	Methane	Ethane	n-Pentane
500	0.0	5.87	1.33	0.0718	0.940	0.000	0.0603	0.160	0.0000	0.840
	0.2	5.74	1.33	0.0782	0.712	0.233	0.0547	0.124	0.1752	0.701
	0.4	5.40	1.32	0.0895	0.469	0.482	0.0490	0.0868	0.365	0.548
	0.6	4.79	1.32	0.108	0.200	0.759	0.0414	0.0417	0.575	0.383
1,000	0.0	3.08	0.882	0.0765	0.9471	0.0000	0.0530	0.308	0.0000	0.693
	0.2	2.98	0.887	0.0858	0.8225	0.128	0.0497	0.276	0.145	0.579
	0.4	2.77	0.897	0.102	0.6834	0.270	0.0461	0.247	0.301	0.452
	0.6	2.39	0.914	0.147	0.5265	0.428	0.0459	0.220	0.468	0.312
	0.8	1.85	0.942	0.250	0.3472	0.612	0.0406	0.188	0.650	0.163
1,500	0.0	2.14	0.811	0.105	0.9412	0.0000	0.0588	0.440	0.0000	0.560
	0.2	2.00	0.816	0.130	0.8460	0.0942	0.0601	0.423	0.115	0.462
	0.4	1.79	0.829	0.181	0.7428	0.194	0.0636	0.415	0.234	0.351
	0.6	1.50	0.869	0.315	0.6204	0.306	0.0739	0.414	0.352	0.235
2,000	0.0	1.59	0.792	0.189	0.9205	0.0000	0.0796	0.579	0.0000	0.421
	0.2	1.44	0.825	0.278	0.8381	0.0690	0.0930	0.582	0.0836	0.334
	0.4	1.21	0.878	0.540	0.7347	0.1379	0.1272	0.607	0.157	0.236

The equilibrium constant for methane is related to the equilibrium constants of the other components and the composition of the system in the following way:[9]

$$K_1 = \frac{Y_1}{X_1} = \frac{1 - (Y_2 + Y_5)}{1 - (X_2 + X_5)} = \frac{1 - (K_2X_2 + K_5X_5)}{1 - (X_2 + X_5)} \quad [2]$$

in which Y_1, Y_2, Y_5 represent the mol fractions of methane, ethane and n-pentane, respectively, the gas phase and X_1, X_2, X_5 represent the mol fractions of the same components in the liquid phase. The limiting value of this expression as the mol fraction of methane approaches zero in both the gas and liquid phases may be obtained by differentiating the numerator and denominator and rearranging. It follows at the limit that

$$K_1 = C\left[K_2 + K_5\left(\frac{1 - C}{C}\right)\right] + C^2\left[\left(\frac{\partial K_2}{\partial X_2}\right) + \left(\frac{\partial K_5}{\partial X_2}\right)\left(\frac{1 - C}{C}\right)\right] \quad [3]$$

Eq 3 has been applied to the data presented in Fig 6 and indicates good agreement with values obtained by extrapolation of the data to the two-phase pressure of the ethane-n-pentane system.

Equilibrium constants for the components of the methane-ethane-n-pentane system at even values of the parameter C have been recorded in Table 2. In addition the corresponding mol fractions of the components in the coexisting liquid and gas phases have been indicated. These data were obtained from the interpolated values of the equilibrium constant by methods that are outlined elsewhere.[9] The values recorded agree well with those obtained directly from Figs 1, 2, and 3.

As was indicated above, the analytical techniques were not such as to permit the distribution of n-pentane to be determined with satisfactory accuracy when it was present only in small amounts. For this reason uncertainty exists in regard to the limiting behavior of n-pentane as C approaches unity. As a result of this uncertainty, values for the equilibrium constant for n-pentane corresponding to a value of C of unity have not been shown in Fig 8. Similar uncertainty made it desirable to eliminate the corresponding curve for ethane in Fig 7.

The marked influence of the nature and amount of the components present upon values of the equilibrium constant of all the components at pressures in excess of 750 psi is demonstrated in Figs 6, 7, and 8. In the case of methane this influence persists throughout the two-phase region of the methane-ethane-n-pentane system. However, for ethane and n-pentane the equilibrium constants become more nearly functions only of pressure and temperature at pressures below 500 psi. It appears that ideal solution behavior is closely approximated for pressures below 250 psi in so far as these components are concerned. However, no experimental measurements were made below 500 psi and this statement is based entirely upon graphical correlation of the data.

The influence of the concentration of other components upon the equilibrium constant for n-pentane is most pronounced at relatively high ratios of ethane to n-pentane. This is shown by the small influence of changes in *C* upon the equilibrium constant for n-pentane in Fig 8 at low values of this parameter and the markedly greater influence of high values. This behavior is similar to that found for n-pentane in the methane-propane-n-pentane system.[3,4]

Summary of Results

This study indicates that at 100°F the critical pressures of all ternary mixtures of methane, ethane and n-pentane are lower than the critical pressure of the methane-n-pentane system at this temperature. This behavior is similar to that which has been found for other ternary mixtures of hydrocarbons so far investigated. The gas-liquid equilibrium constant of each component is markedly influenced by the nature and amount of other components present. The influence persists to pressures well below 500 psi, particularly in the case of the lighter components. This work serves further to emphasize the fact that the so-called "equilibrium constant" is a function of the state of the system rather than a function only of pressure and temperature for systems in which the components differ markedly from one another in regard to pertinent physical properties.

Because of the inherent complexity of the state of a heterogeneous multicomponent mixture, some difficulties are to be expected in obtaining general correlations of equilibrium constants for the lighter hydrocarbons in such systems. Since the chemical potential of a component in a phase is a function of the state only of that phase, rather than that of the system as a whole, its use offers somewhat better promise for purposes of generalization. However, insufficient information is as yet available to permit serious attempt to obtain accurate correlations.

Acknowledgment

This investigation was carried out under a fellowship supported by the Standard Oil Company of California. The cooperation and financial assistance of this organization is acknowledged.

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DISCUSSION

W. T. Lietz*—This paper, like all previous ones presented by Dr. Lacey and his co-

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workers, is an excellent contribution to the general information on phase behavior of ternary systems. The equilibrium constants of these simplified systems have been applied successfully to calculations on crude oils, provided the gravity is not too low. It is only to be regretted that practically no data are available for pressures over 3000 psi, especially since with the increased drilling depths reservoir pressures over 8000 psi and temperatures of 275°F or more are quite common. In our computations we have found that the use of extrapolated equilibrium constants for the calculation of phase behavior of reservoir fluids leads to results which differ considerably from experimental observations.

J. E. SHERBORNE*—Dr. Lacey and his co-workers have presented another significant contribution to add to the long list of excellent researches they have performed for the petroleum industry. The data presented further supplement the somewhat disconcerting knowledge that the kind and amount of other components in a system have an important bearing on the equilibrium constant.

It is interesting to observe, however, that Dr. Lacey offers us the possibility of another means of correlating complex hydrocarbon behavior in the use of the chemical potential. Dr. Lacey observes that insufficient data are available concerning the chemical potential to permit its use in correlation at present. It would be of interest to know Dr. Lacey's opinion as to, first, whether more information relative to the chemical potential could be made available by further analysis of the existing experimental data, or if further experimental work will be required; and second, if further experimental work is required, would it be a relatively small amount supplementary to that already performed, or would extensive experimental research be required? In short, is there a chance that a correlation based on chemical potentials will be available to the industry reasonably soon?

M. BENEDICT†—Reliable experimental measurements of the composition of coexistent liquid and vapor hydrocarbon mixtures such as are given in this paper are essential for accurate prediction of phase equilibria in hydrocarbon systems. Because of the practical impossibility of measuring all possible mixtures at all temperatures and pressures of interest, some method of correlating and extending these data is required. As suggested by the authors, the chemical potential, or fugacity, of each component in each phase, is the property preferred for correlation.

An equation of state,[10] initially developed for mixtures of methane, ethane, propane and butane, provides a method for predicting these chemical potentials, and from them, equilibrium constants, or *k*-values. Although there has not been time to make a careful study of the best values for the constants in the equation of state for pentane, preliminary calculations indicate that the results of this paper may be correlated satisfactorily by means of this equation of state. The maximum deviation of equilibrium constants predicted in this way from observed equilibrium constants is around 4 pct for methane, 4 pct for ethane and 10 pct for pentane. The dependence of equilibrium constants on composition is correctly represented.

G. W. BILLMAN, B. H. SAGE and W. N. LACEY (authors' reply)—This laboratory is in entire agreement with the statements by W. Tempelaar Lietz in regard to the difficulty of extrapolating equilibrium constants available to the higher pressures encountered in underground reservoirs. At the present time work is in progress at this laboratory upon another ternary system involving one component of a somewhat higher molecular weight thus yielding correspondingly higher two-phase pressures. One of the primary limitations to the extension of such studies to the higher pressures lies in the difficulty of obtaining pure materials of sufficiently high molecular weight to obtain two-phase pressures in excess of 10,000 psi. If an impure constituent is employed as the component of high molecular weight significant differences in the distribution of the heavier components making up this constituent are obtained in the liquid and the gas phases.

It is believed that if suitable methods of analysis are available for the materials of

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† Hydrocarbon Research, Inc., New York, New York.

[10] Benedict, Webb and Rubin: *Jnl. Chem. Phys.* (1942) 10, 747.

higher molecular weight investigations can be carried to the ranges of pressure and temperature of interest in petroleum production. However, the difficulty in obtaining adequate supplies of pure compounds of high molecular weight has made such data relatively scarce. When volumetric data for systems involving components of high molecular weight are available it will be possible to evaluate the constants of the Benedict equation of state for these components. By the application of this equation the corresponding phase behavior may be estimated with an accuracy equivalent to that with which this equation of state predicts the phase behavior of mixtures of the lighter hydrocarbons.

In regard to the discussion by Mr. Sherborne, it is believed that a significant contribution toward the application of chemical potentials to the prediction of the composition of coexisting phases of hydrocarbon systems has been made by Manson Benedict.[10] In another discussion[11] of this paper by Manson Benedict it is indicated that his equation of state which is already available will predict the equilibrium constants for the components of the methane-ethane-n-pentane system with uncertainties varying from 4 to 10 pct over the entire range of composition. It is believed that the accuracy with which chemical potentials may be derived from this equation of state or by application of other methods will be improved gradually as additional data are accumulated. The possibility of the gradual improvement of accuracy without the need of a complete revision of the method of correlation is one of the strongest arguments in favor of the use of chemical potentials in this connection. This advantage also applies to the prediction of volumetric and thermodynamic data from the partial values of the corresponding properties.

R. J. Schilthuis*—The current paper by Billman, Sage, and Lacey represents another addition to the knowledge of complex hydrocarbon phase behavior. Over the years, Dr. Lacey and his various associates have been outstanding contributors to this field of basic knowledge which has proved to be of great value to the petroleum branch of the mineral industries. The work presented in the current paper needs no technical comment. However, having learned of the fact that Dr. Lacey is to receive the Lucas Award of this year, I would like to take this opportunity to express my sincere feeling that the award is highly merited on the basis of his outstanding services to industry in the fields of scientific research and education.

[11] Lewis: Proc. of Amer. Acad. Arts and Sci. (1907) 43, 273.

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S. E. Buckley*—It is always a real pleasure to read or hear a paper prepared by Dr. Lacey and his associates, not solely because each paper has technical merit and is clearly and concisely prepared in well-chosen words, but because each paper is another mile post representing substantial, practical progress. During the years that Dr. Lacey and his many co-workers have labored with hydrocarbon systems, they have progressed steadily and continuously through the lowlands of individual hydrocarbons, the rising plateau of binary mixtures, and now into the higher altitudes of ternary systems. The highest peaks of multicomponent mixtures are clearly in sight ahead.

One who reads or listens to one of these straightforward and lucid explanations of the manner in which hydrocarbons behave is apt to get the impression that hydrocarbon mixtures are really very simple things to deal with. One whose primary technical pursuits in the petroleum industry do not involve detailed calculation of the behavior of individual hydrocarbons or their mixtures may overlook the fact that the entire petroleum industry is a hydrocarbon industry, founded on and consisting in the exploitation, production, processing, transportation, and marketing of hydrocarbons, that millions of dollars are invested on the basis of processes and designs directly dependent on an exact quantitative knowledge of what hydrocarbons will do in a known environment.

If, in retrospect, the job looks simple, no greater tribute could be paid to the foresight, the careful planning and execution which Dr. Lacey and his co-workers have demonstrated in giving to the petroleum industry the wealth of information which year after year has come from their papers.

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A Radial Turbulent Flow Formula

By Jack R. Elenbaas* and Donald L. Katz,* Member AIME

(Tulsa Meeting, October 1947)

Abstract

A radial turbulent flow formula has been developed which permits the computation of the pressure drop for radial flow in gas wells whether the flow is laminar, turbulent, or partially laminar and partially turbulent. Using the formula a complete back-pressure curve has been calculated and analyzed by a comparison with existing back-pressure curves. A procedure is presented for computing the permeability of the porous media when the porosity, sphericity and average particle diameter are known.

Introduction

Recent studies on the flow of fluids through porous media have provided new methods for computing flow under turbulent conditions. The present study was initiated as an investigation of pressure-drop computations for flow through porous sands in gas wells and as an analysis of present-day back-pressure tests.

Although laminar flow exists in the producing formation of gas wells under normal flow rates, turbulent flow does take place adjacent to the well bore. As the flow rate is increased, turbulent flow exists further and further into the producing formation and under open-flow conditions in relatively deep wells a considerable portion of the flow through the sand will be turbulent.

In order to calculate a complete back-pressure curve for relatively deep wells without resorting to extrapolation of curves drawn from data obtained in back-pressure tests or calculations made in the completely laminar region, it was necessary to have some means of calculating pressure drop for flow through porous sands under turbulent conditions.[4,6] As a result, a radial turbulent flow formula was derived from the equations recently presented by Brownell and Katz.[1]

A rigorous solution of this equation involves a trial and error graphical integration. By making the assumptions of average viscosity, temperature and compressibility factor of the flowing gas, it was possible to graphically integrate the relation for the general case of radial flow of gases through the porous sand of gas wells. A chart has been prepared relating the value of the integral to the radius of the well bore and to the Reynolds number of the flowing gas. The chart actually performs the graphical integration and the solution of the formula is then reduced to a simple trial and error calculation. A typical back-pressure curve is calculated to show the transition from laminar to turbulent flow.

This paper will briefly describe the procedures for computing flow through porous media, including a method for predicting sand permeability from porosity and grain size and shape.

Flow through Porous Media

Brownell and Katz[1] recently reported a correlation for computing flow of fluids through porous media by the use of an enlarged Reynolds number and friction factor in which the porosity of the bed is included as an additional prime variable.

The enlarged Reynolds number com-

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[1] References are at the end of the paper.

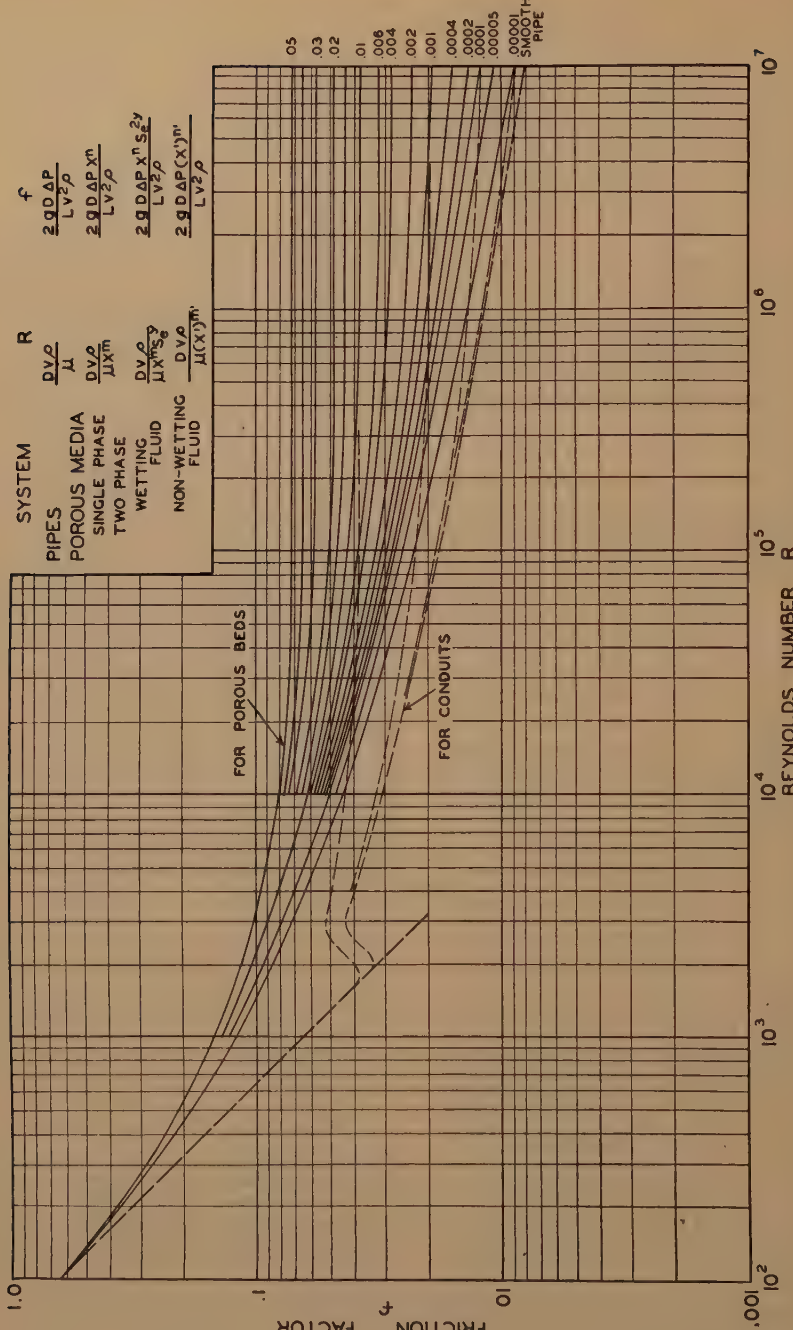

Fig 1—Friction factors for porous media.

pletely defining flow through a porous bed appears as follows:

$$Re = \frac{Dv\rho}{\mu X^m} \qquad [1]$$

where,

Re = Reynolds number, dimensionless.
D = average diameter of the particles, ft.
v = velocity of the fluid based upon the total cross section, ft. per sec.
ρ = density of the fluids, lb. per cu. ft.
μ = viscosity of the fluid, lb. per ft sec.
X = porosity of the bed
$= \frac{\text{volume of voids}}{\text{total volume of bed}}.$
m = exponent to be applied to porosity as determined from Fig 2.

The Fanning friction factor equation, another definition of the system, has also been enlarged and is given in Eq 2:

$$\frac{dP}{dr} = \frac{fv^2\rho}{2gDX^n} \qquad [2]$$

in which,

P = pressure, lb per sq ft.
r = length of path of flow = radius of producing formation for radial flow in wells, ft.
f = friction factor, dimensionless.
g = gravitational acceleration, ft per sec.[2]
n = exponent to be applied to porosity as determined from Fig 2.

For flow through pipes, a plot of Reynolds number versus friction factor consists of a single 45° line in the laminar flow region and a series of lines in the turbulent region, the latter having the roughness of the pipe as a parameter. The relationship between the Reynolds number and friction factor should be the same for flow through porous media if the systems are properly defined. Brownell and Katz[1] have presented such a plot (Fig 1) with the roughness of the particles as a parameter.

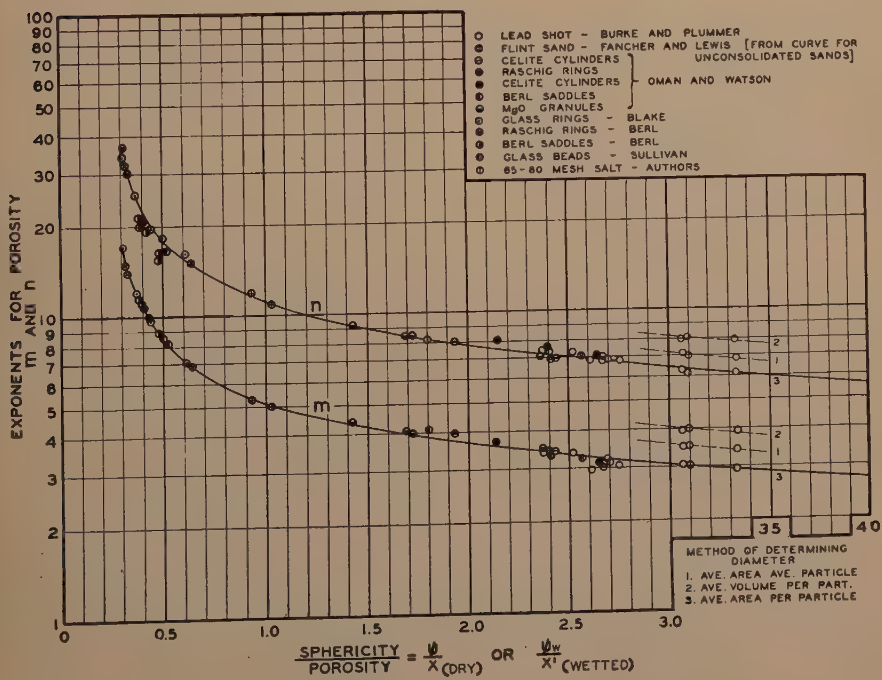

FIG 2—EXPONENTS FOR THE POROSITY FUNCTION.

Porosity-permeability Correlation

From Darcy's law and the relationship between the friction factor and Reynolds number in the laminar flow region, an equation defining permeability in terms of the porosity of the bed and the sphericity and average diameter of the particles can be derived.

Darcy's law, as applied by Muskat[2] to the radial single-phase flow of fluids in wells, may be used to compute the pressure drop caused by friction where the flow is completely laminar. The law is expressed mathematically as follows:

$$v = \frac{K}{\mu}\frac{dP}{dr} \qquad [3]$$

where,

K = permeability of the porous sand.

In the laminar flow region of Fig 1 the friction factor, f, is equal to 64 divided by the Reynolds number and, hence, combining Eq 1 and 2 one has

$$\frac{dP}{dr} = \frac{64v^2\rho\mu X^m}{Dv\rho 2gDX^n} = \frac{32v\mu}{gD^2X^{n-m}} \qquad [4]$$

By a comparison of Eq 3 and 4 it follows that

$$K = \frac{gD^2X^{n-m}}{32} \qquad [5]$$

In order to compute the permeability from Eq 5 the porosity of the bed and the sphericity and average diameter of the particles must be known.

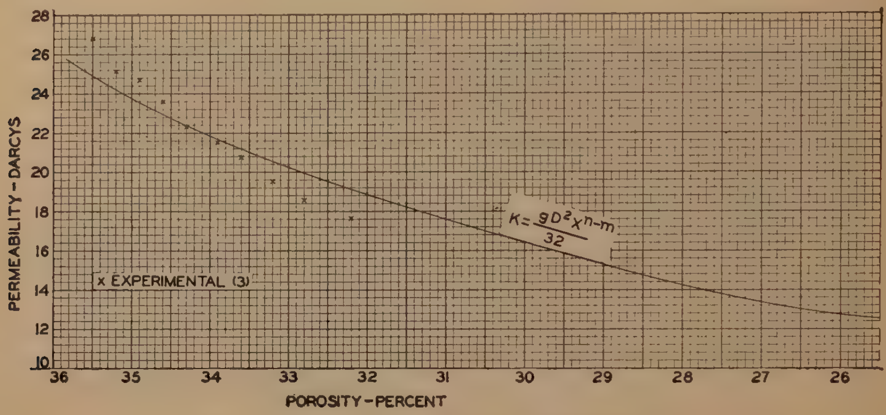

FIG 3—EQUATION FOR PREDICTING PERMEABILITY.

The average particle diameter may be calculated from the screen analysis of the sand by Eq 6. The diameter,

$$D = \sqrt{\frac{\sum\left(\frac{M}{d}\right)}{\sum\left(\frac{M}{d^3}\right)}} \qquad [6]$$

in which

d = the average size of a given weight fraction taken as the arithmetic average of the screen openings that pass the particles and retain the particles.

M = the weight fraction of a given particle size.

of the particle obtained from Eq 6 is the particle which has the average area. This method has been selected and presented by Brownell and Katz[1] instead of the method of Blake[3] or Fancher and Lewis[4] because it brings the data on porous beds composed of particles of many sizes into better agreement with the data for beds containing particles of a single size.

Particle sphericity is defined as the area of a sphere of the same volume as the par-

ticle divided by the surface area of the particle. Brownell and Katz[1] have given sphericities for a number of materials and have suggested that the sphericity of most granular particles will be between 0.6 and 0.8. Sphericity can be calculated from Eq 5 if the permeability of a porous solid of given screen analysis is known at some value of porosity.

Johnson and Taliaferro[5] have presented a number of values of permeability at various porosities of a 48-65 mesh Wilcox sand. They have also given a complete screen analysis of the sand. The data are shown on Fig 3 along with the curve of Eq 5 using a particle sphericity of 0.67. The correlation is fairly good. Actual experimental values of permeability are certainly preferred if they are available; however, in the absence of experimental data the use of Eq 5 is a method for predicting permeabilities. The correlation breaks down entirely if the sand contains cementing material.

Derivation of the Radial Turbulent Flow Formula

A radial flow formula has been developed which permits the computation of the pressure drop caused by friction when the flow is in the laminar, transition or completely turbulent region.

Fig 4 is a graphical illustration of the radial flow problem. The fluid is flowing from r_1 to r_2. Since the problem is one of steady state flow, the weight of gas flowing per unit time is a constant and, thus, the following relationship is true:

$$2\pi r_1 h_1 v_1 \rho_1 = 2\pi r_2 h_2 v_2 \rho_2 = 2\pi r h v \rho = W \quad [7]$$

where,

h = sand thickness, feet.

W = weight of flowing gas, pounds per second.

Solving for v and squaring the complete equation,

$$v^2 = \frac{W^2}{4\pi^2 r^2 h^2 \rho^2} \quad [8]$$

Substituting this value of v^2 in Eq 2, it becomes,

$$\frac{dP}{dr} = \frac{W^2 f}{8gDX^n \pi^2 h^2 r^2 \rho} \quad [9]$$

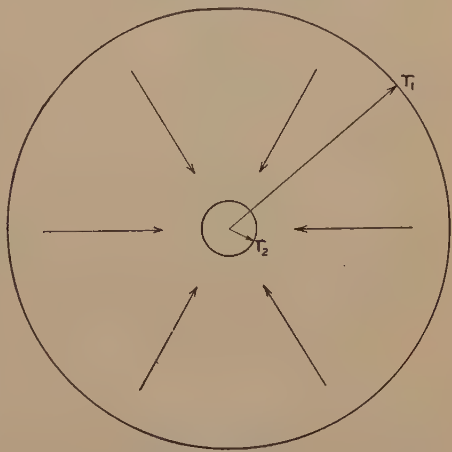

Fig 4—Diagrammatic sketch of radial flow.

In order to integrate Eq 9, it is necessary to express the density in terms of the pressure, P. This can be accomplished by using the ideal gas law and the compressibility factor:

$$PV = ZNRT \quad [10]$$

in which,

P = pressure

V = volume.

Z = compressibility factor.

N = number of mols.

R = gas constant per mol.

T = absolute temperature.

The gas density can be written in the form,

$$\rho = \frac{29G}{V} \quad [11]$$

where,

G = gas gravity

$$= \frac{\text{molecular weight of the gas}}{\text{molecular weight of air}}.$$

29 = molecular weight of air.

Combining Eq 10 and 11,

$$\rho = \frac{29GP}{ZRT} \quad [12]$$

Substituting Eq 12 in Eq 9 and re-arranging the terms:

$$PdP = \frac{W^2RTZf}{8gDX^n\pi^2h^2 29G}\frac{dr}{r^2} \qquad [13]$$

Assuming that T and Z are constant, they can be removed from within the integral and Eq 13 can be graphically integrated in the following form:

$$\int_{P_1}^{P_2} PdP = \frac{W^2RTaZa}{8gDX^n\pi^2h^2 29G}\int_{r_1}^{r_2}\frac{fdr}{r^2} \qquad [14]$$

Combining the constants and integrating the left member of the equation:

$$P_2^2 - P_1^2 = 0.00000202 \frac{W^2TaZa}{DX^nh^2G}\int_{r_1}^{r_2}\frac{fdr}{r^2} \qquad [15]$$

where,

- P = pressure, psi.
- W = weight of gas flowing, lb per sec.
- Ta = average temperature of flowing gas, °R.
- Za = average compressibility factor of the flowing gas.
- D = average diameter of the particles, ft.
- X = porosity of porous bed
- n = exponent to be applied to porosity as determined from Fig 2.
- h = sand thickness, ft.
- G = gas gravity
- r = radius, ft.

Substituting Eq 5 in Eq 15 and combining the constants:

$$P_2^2 - P_1^2 = 5{,}950 \frac{W^2DTaZa}{KX^mh^2G}\int_{r_1}^{r_2}\frac{fdr}{r_2} \qquad [16]$$

in which the units are the same as in the previous equation except for the permeability, K, which is in darcys. The formula may be used in the form of either Eq 15 or Eq 16.

To solve the integral it is necessary to assume values of r between r_1 and r_2, find f at each assumed value of r, plot $\frac{f}{r^2}$ versus r, and measure the area under the curve between the limits r_1 and r_2. The friction factor, f, can be evaluated from Fig 1 if the Reynolds number and roughness of the particles are known. For any specific homogeneous porous media the roughness of the particles and D and X^m in the Reynolds number are essentially constant throughout the sand. The viscosity of the gas does not vary considerably in the usual friction drop pressure range within the porous sand at constant temperature and an average value of the viscosity may be used in determining the Reynolds number. Because of the geometry of the radial flow problem, the mass velocity of the gas, vp, in pounds per square foot per second is continually increasing as the gas approaches the well bore. Hence, the value of the mass velocity of the gas must be determined at each assumed value of r in order to evaluate the Reynolds number and, consequently, the friction factor. Solving Eq 7 for vp, it is easily seen that at a given weight of gas

$$vp = \frac{W}{2\pi rh} \qquad [17]$$

flow, W, in pounds per second and height of producing sand, h, the mass velocity of the gas can be determined at any value of r.

To simplify the solution of Eq 15 or 16, Fig 5 has been prepared. The value of the integral $\frac{fdr}{r_2}$ is plotted versus the radius r_2 with the Reynolds number of the flowing fluid at r_1 as a parameter. At a radius r_1 of 500 ft the pressure in the producing formation will be substantially equal to the reservoir pressure and it has, therefore, been chosen as r_1 in preparing Fig 5. The plot was prepared by the tedious procedure of actually performing the graphical integration for values of the Reynolds number at 500 ft of 1000, 100, 10, 1, 0.1, and 0.01. By the method of cross-plotting the remaining curves were determined and placed on the figure. A curve showing the limit of the laminar flow region has also been drawn on the figure. The curve is actually one of a

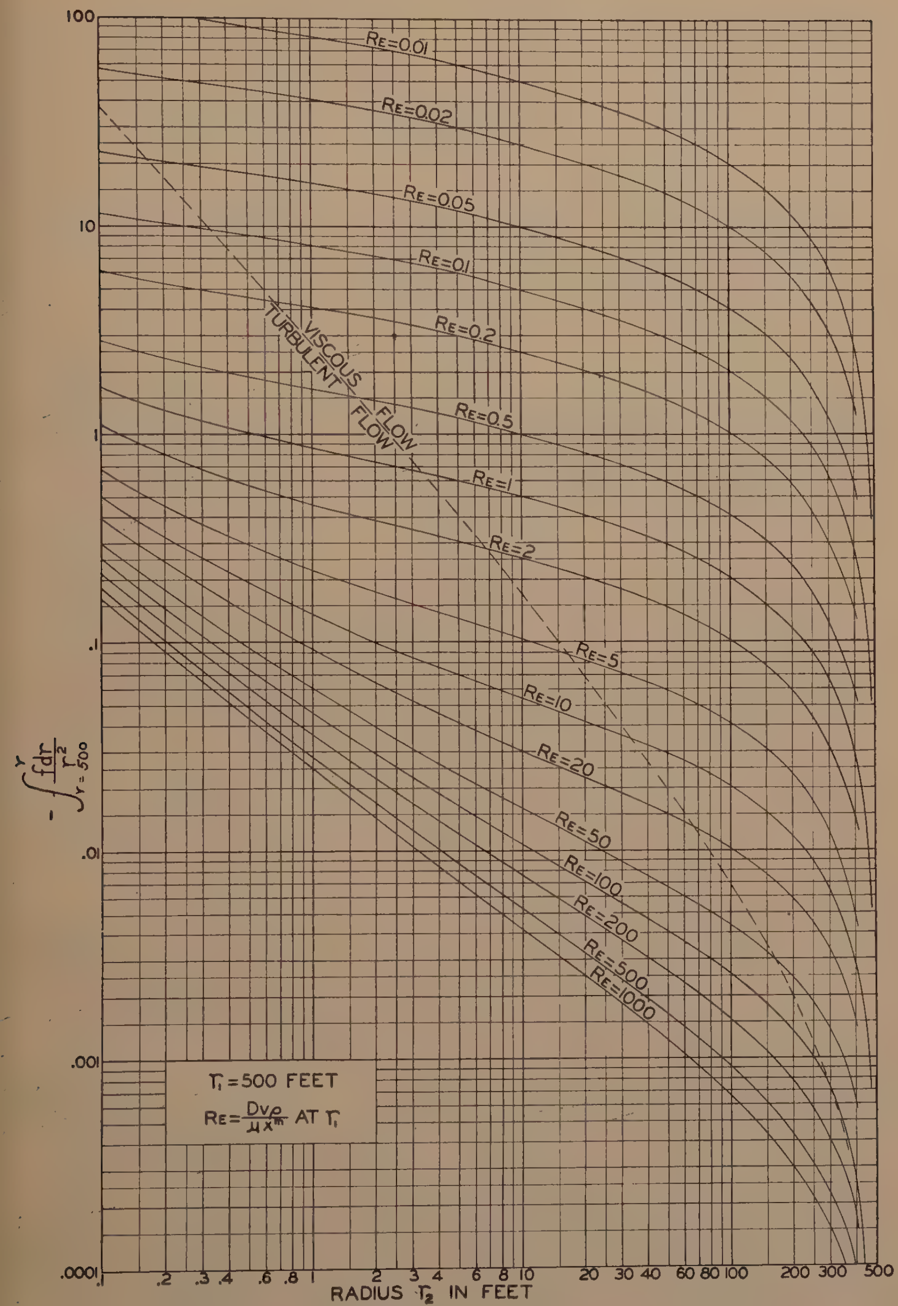

FIG 5—CHART FOR EVALUATING INTEGRAL IN RADIAL FLOW FORMULA.

constant Reynolds number of 150 at which the transition from laminar to turbulent flow occurs. In preparing Fig 5 a relative particle roughness of 0.0001 has been used. Brownell and Katz[1] have suggested that this roughness will suffice for most porous gas-producing sands. Fig 5 may be used in conjunction with Eq 15 or 16 for completely laminar flow, partially laminar and partially turbulent flow, or completely turbulent flow.

Sample Calculation of Pressure Drop for the Radial Flow of Natural Gas in a Well

Predict the pressure drop for the radial flow of natural gas under the following conditions:

Depth of well	5000 ft.
Reservoir pressure	2100 psi gauge.
Height of producing sand	1 ft.
Casing size	6⅝ in.
Reservoir temperature	115°F.
Gas gravity	0.65.
Porosity of sand	0.26.

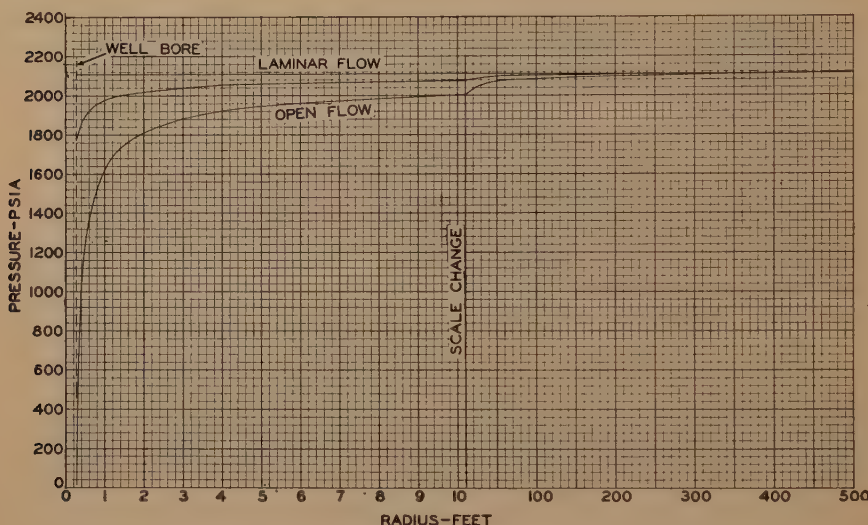

Fig 6—Calculated pressure gradient around well.

Fig 6 has been prepared for the well described in the following section using Eq 15 and Fig 5. It shows the pressure gradient curves in the producing sand at various rates of flow. The three curves are for rates of flow of 72,000,000; 34,800,000; and 170,000 standard cu ft per day. For the two high rates of flow, the flow is turbulent in the producing formation to radii of 220 and 110 ft, respectively. The figure illustrates the fact that the majority of the pressure drop occurs in the turbulent region adjacent to the well bore. It also indicates that the assumption of 500 ft as the radius at which the pressure in the producing formation is substantially equal to the reservoir pressure is an accurate one.

The sand will be assumed to be the 48–65 mesh Wilcox sand from which the permeabilities on Fig 3 were obtained.

Screen analysis of sand:

through 35 mesh on 48 mesh	0.06 pct.
through 48 mesh on 65 mesh	95.35 pct.
through 65 mesh on 80 mesh	1.72 pct.
through 80 mesh on 100 mesh	2.67 pct.
through 100 mesh on 150 mesh	0.19 pct.
through 150 mesh on 200 mesh	0.01 pct.
	100.00 pct.

Sphericity	0.67.
Permeability (from Fig 1)	12.74 darcys.

Average particle diameter:

Mesh	M	d in.	d^2	$\frac{M}{d}$	$\frac{M}{d^2}$
35–48	0.0006	0.01400	0.000002750	0.043	219
48–65	0.9535	0.00990	0.000000970	96.310	983,000
65–80	0.0172	0.00755	0.000000430	2.280	40,000
80–100	0.0267	0.00635	0.000000256	4.205	104,250
100–150	0.0019	0.00495	0.000000121	0.384	15,650
150–200	0.0001	0.00350	0.000000043	0.029	2,333
				103.251	1,145,452

$$D = \sqrt{\frac{103.25}{1,145,500}} = 0.00949 \text{ in.}$$

$$= 0.000791 \text{ ft.}$$

Eq 15:

$$P_2^2 - P_1^2 = \frac{0.00000202 W^2 Ta Za}{D X^n h^2 G} \int_{r_1}^{r_2} \frac{f dr}{r^2}$$

$$X = 0.26.$$

$$\psi \text{ (sphericity)} = 0.67.$$

$$\frac{\psi}{X} = 2.58.$$

From Fig 2:

$$m = 3.23.$$

$$n = 6.92.$$

Therefore,

$$X^n = (0.26)^{6.92} = 0.00009.$$

$$G = 0.65.$$

$$h = 1.$$

$$D = 0.000791.$$

$$g = 32.2.$$

$$R = 1544.$$

$$Ta = 115°\text{F} = 575°R.$$

$$P_1 = 2100 \text{ psi gauge} = 2114 \text{ psia.}$$

$$r_1 = 500 \text{ ft.}$$

$$r_2 = \frac{6.652}{12} = 0.2773 \text{ ft}$$

$$P_2^2 - (2114)^2 = \frac{(0.00000202)(575)W^2 Za}{(32.2)(0.000791)(0.65)} \int_{500}^{0.2773} \frac{f dr}{r^2}$$

$$P_2^2 - 4,475,000 = 25,130 W^2 Za \int_{500}^{0.2773} \frac{f dr}{r^2}$$

Let W = 10 lb per sec.

$$Q = \frac{(10)(3600)(24)(379)}{(29)(0.65)}$$

$$= 17,390,000 \text{ standard cu ft per day.}$$

Assume P_2 = 2000 psia

$$P_a = \frac{P_1 + P_2}{2} = \frac{2114 + 2000}{2} = 2057 \text{ psia.}$$

From Fig 5 of reference 7:

Pseudo Critical Temperature of a 0.65 gravity gas = 374°R.

Pseudo Critical Pressure of a 0.65 gravity gas = 669 psia.

Reduced Temperature = $575/374$ = 1.54.

Reduced Pressure = $2057/669$ = 3.08.

From Fig 1 of reference 8:

Compressibility factor of the gas, Za = 0.792.

Reynolds number at r_1 of the gas:

$$D = 0.000791 \text{ ft.}$$

$$v\rho = \frac{W}{2\pi r h} = \frac{(10)(3600)}{(2\pi)(500)(1)}$$

$$= 11.45 \text{ lb per ft}^2 \text{ hr.}$$

From Fig 6 of reference 9 the viscosity of the gas at a temperature of 575°R and a pressure of 2057 psia is obtained.

$$\mu = 0.0176 \text{ centipoises.}$$

$$X^m = (0.26)^{3.23} = 0.013.$$

$$Re_{500} = \frac{D v \rho}{\mu X^m} = \frac{(0.000791)(11.45)}{(0.0176)(2.42)(0.013)} = 16.4$$

From Fig 5:

$$\int_{500}^{0.2773} \frac{f dr}{r^2} = -0.217.$$

Then,

$$P_2^2 - 4,475,000 = (25,130)(10)^2(0.792)(-0.217).$$

$$P_2^2 = 4,475,000 - 431,500 = 4,043,500.$$

$$P_2 = \sqrt{4,043,500} = 2010 \text{ psia.}$$

If the difference between the assumed and the calculated values of P_2 had been greater than 50 psia, it would have been necessary to make a second assumption of P_2 (ordinarily the previous calculated value) and recalculate P_2.

Calculated Back-pressure Curve

By making a series of computations similar to the previous sample calculation at various rates of flow, a complete back-pressure curve can be determined. Fig 7 is a back-pressure curve for the gas well described in the previous section. It will be noticed immediately that the curve is not a straight line as all experimental back-pressure curves are assumed to be. Since the flow rates on almost all back-pressure curves are neither in the completely laminar nor in the completely turbulent flow region,

it is believed that no back-pressure curves would be straight lines if a wide enough range of rates of flow were used in obtaining the experimental or test data. This, of course, would mean that the usual extrapolation of back-pressure curves to obtain the open-flow rate may be considerably in error. Rawlins and Schellhardt[10] made studies of the character of flow of gas through various porous media. The majority of the back-pressure curves resulting from this study were curved and very similar to Fig 7.

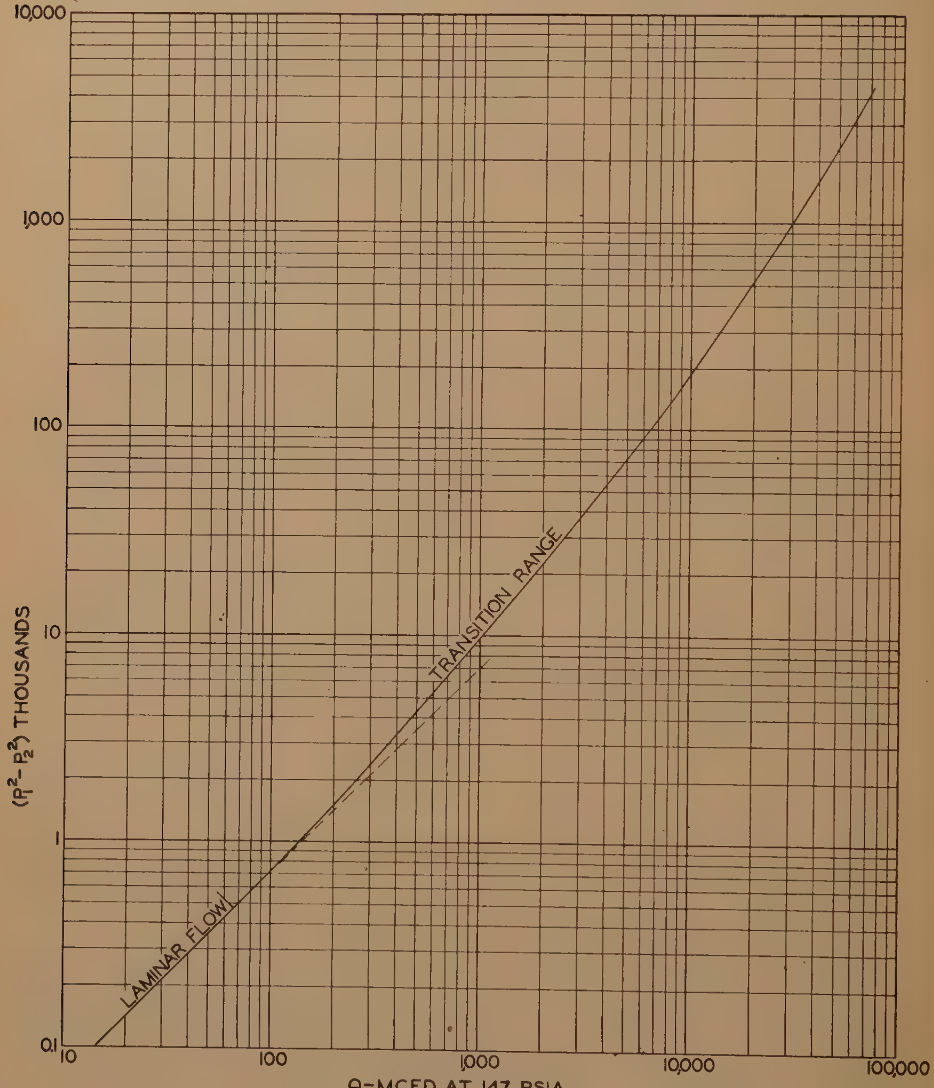

Fig 7—Back-pressure curve

Binckley[11] has stated that for steady state isothermal flow in a system of constant effective permeability the slope of the back-pressure curve is 0.5 for completely turbulent flow and 1.0 for completely lami-

nar flow. These limiting slopes have been confirmed in laboratory experiments made by Muskat and Botset.[12] The back-pressure curve of Fig 7 commences in the completely laminar flow region and has a slope of 1.0. Completely turbulent flow is not attained in the given well before the open flow rate is reached so that the slope of the curve does not reach 0.5 although it does approach that value.

Analyzing Eq 15 and noting that in the completely laminar flow region the friction factor is equal to 64 divided by the Reynolds number, it can be shown that the resulting equation would appear as follows:

$$P_2^2 - P_1^2 = 0.000812 \frac{\mu ZaTaW}{D^2X^{n-m}hG} \ln \frac{r_2}{r_1} \quad [18]$$

For a given well, this is equivalent to saying that the difference in the squares of the pressures is equal to the product of a constant and the rate of flow and when plotted as a back-pressure curve, the above equation would be a straight line with a slope of 1.0.

In the completely turbulent region the friction factor becomes relatively constant and Eq 15 reduces to the following form:

$$P_2^2 - P_1^2 = 0.00000202 \frac{W^2TaZaf}{DX^nh^2G} \left(\frac{1}{r_1} - \frac{1}{r_2}\right) \quad [19]$$

When plotted as a back-pressure curve the above equation would be a straight line and would have a slope of 0.5. The radial turbulent flow formula is then in complete agreement with the limiting conditions suggested by Binckley[11] and Muskat and Botset.[12]

Binckley[11] has also stated that in many gas fields the slope of the back-pressure curves are in the vicinity of 0.85. This is adequate proof that flow in the major portion of the natural gas wells is not in the completely laminar region.

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DISCUSSION

G. H. Fisher*—The paper presents a comprehensive discussion of the theory and derivation of a radial turbulent flow formula permitting the computation of pressure drops for radial flow in gas wells independent of the type of flow, whether laminar, turbulent, or partially laminar and partially turbulent. The application of the method, however, requires that certain information be available which many times is lacking when it is necessary to determine back-pressure curves or gas well performance.

It seems that from a theoretical standpoint the equations presented would be adaptable provided the information is available and that one performs the trial and error calculations necessary to convert the data into usable form by means of the formula. Its use would be limited however in many instances by lack of data, particularly with regard to sphericity of the sand grains and average particle diameter. In the limestone and dolomite fields, these would obviously be impossible to determine.

Although it is felt that the derivation of equation represents a step forward in theoretical considerations of performance of gas wells, it is believed that the inherent lack of information

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will in many cases retard its application on a wide scale in actual field operations.

A. L. VITTER, JR.*—Messrs. Elenbaas and Katz give an explanation for the deviation of the slope of back-pressure tests from unity on the basis of turbulent flow in the immediate vicinity of the well bore, which seems reasonable. There has been some thought that in the case of gas-condensate wells the condensation of the liquid phase in the reservoir causes sufficient reduction in permeability to gas to explain this behavior. As an example, a well producing with a ratio of 15,000 cu ft per barrel and a drawdown of 500 psi would be expected to condense liquid to the extent of a 2 pct pore space saturation, which would cause a reduction in permeability to gas of 6 pct in the immediate vicinity of the well bore. This is an extreme drawdown and such a reduction in permeability is not sufficient to cause the effect observed. Furthermore, it is not reasonable to expect that a liquid with such a low pore space saturation is mobile to any appreciable extent in the light of our present concepts of effective permeability, and thus an accumulation of higher saturations near the well bore by drainage and consequent larger reduction in permeability to gas is not reasonable. In addition, the immobility of such low saturations is demonstrated by the increase in gas-oil ratios in gas-condensate fields as the reservoir pressure decreases.

The Klinkenburg[13] effect is an even smaller effect and cannot explain the observation of a decreasing slope of the back-pressure test at higher rates of flow.

This paper is very interesting and the basic work on flow in porous media that the Ann Arbor group is doing is a very valuable contribution to the literature. It is unfortunate that the authors did not choose to present a paper on the basic work before the AIME as it would be of even greater interest than the present paper. This discussion is limited inasmuch as reference 1 of the authors' paper has not yet been published. Their correlation of unconsolidated sands on the basis of the parameters' porosity and sphericity is a step ahead and perhaps will lead the way to parameters describing the type and degree of cementation in consolidated sands.

* The California Co., New Orleans, La.

[13] L. J. Klinkenburg: The Permeability of Porous Media to Liquids and Gases. Amer. Petr. Inst. Drill. and Prod. Practice (1941) 200.

C. W. BINCKLEY*—Dr. Katz and Mr. Elenbaas have given us a very interesting and enlightening paper dealing with the theory of steady state flow of gas through permeable sands and a method of computing the back-pressure curve for gas well performance when certain physical properties of the producing formation are known.

Back-pressure test data taken on many wells producing from zones of different porosity and permeability indicate that, within the flow range of testing and producing operation, the flow of gas into the well bores of gas wells seldom, if ever, follows the law of laminar or turbulent flow. In the testing of clean gas wells in the absence of changing liquid saturation of the formation near the well bore, and in the absence of severe temperature changes the resulting back-pressure curves show the flow of gas through the producing formation to be a combination of laminar and turbulent flow since the curves have a slope between 0.5, the turbulent flow value, and 1.0, the laminar flow value.

Referring to the authors' sample back-pressure curve in Fig 7, the absolute potential is approximately 70,000 Mcfd. The flow range for the back-pressure testing of such a well would be ordinarily between 4000 Mcfd and 25,000 Mcfd. Thus, the example cited checks field experience with respect to combination flow. However, field tests conducted over a wide range of flow rates on wells in good producing condition often do not show the upward bending trend of the back-pressure curve shown in the authors' Fig 7.

During 1945 and 1946 I supervised the experimental back-pressure testing of seven gas wells completed in the dolomite producing zones of the South Hugoton gas field. The purpose of the testing was to determine, by a wide range of observed data, the laminar and combination laminar and turbulent flow limits of well performance by the change of slope in the back-pressure curves.

The results of the experimental tests are shown by the two back-pressure curves of Fig 8 which are typical of the seven curves obtained.

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The rates of flow on the two wells varied from 35 to 2500 Mcfd and each rate of flow continued for 24 hr to ensure a high degree of stabilization. The wells are located five miles

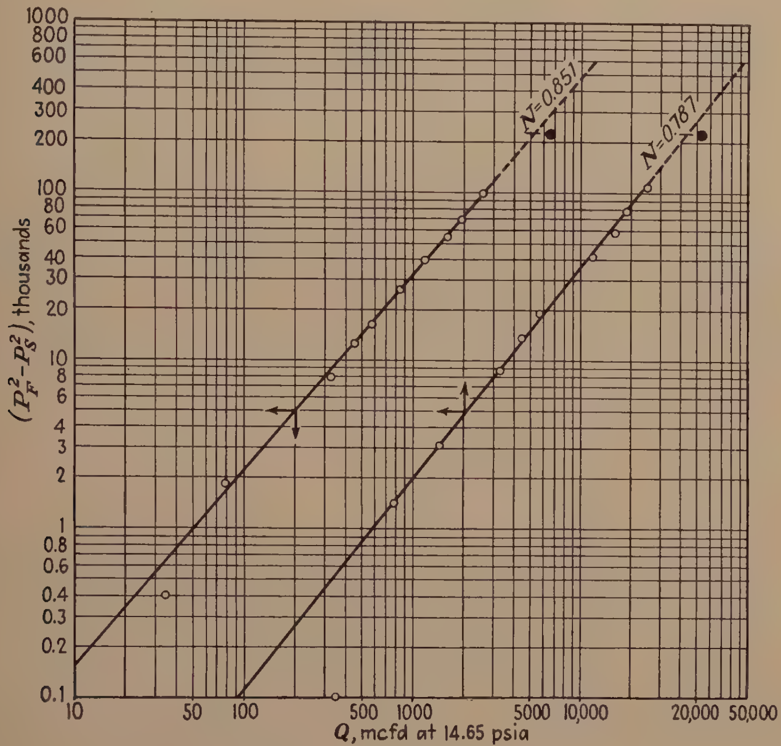

FIG 8—BACK-PRESSURE TEST.

Line $N = 0.851$—Phillips Petroleum Co. Gorman No. 1, Hugoton gas field. Date: 11-19-45. S.I.P.: 428.8 psig. Complete stabilized open flow pitot gauge: 6250 Mcfd. First flow as percentage of potential: 0.007. Last flow as percentage of potential: 49.1. Absolute potential: 5200 Mcfd.

Line $N = 0.787$—Phillips Petroleum Co. Janet No. 1., Hugoton gas field. Date: 11-19-45. S.I.P.: 430.1 psig. Complete stabilized open flow pitot gauge: 4600 Mcfd. First flow as percentage of potential: 0.008. Last flow as percentage of potential: 58.4. Absolute potential: 4225 Mcfd.

apart, and it is believed that there was no interference between the wells during testing.

The large black dots shown near the absolute potential cut off points on the two curves of Fig 8 are the actual stabilized open flows for each well and were measured with a Pitot tube while the wells were flowing open to the atmosphere. It is apparent, after comparing the open flows with absolute potentials, that the absolute potentials are not inflated by straight line extrapolation of the curve beyond the range of observed and calculated data.

The range of calculated data, based on observed pressures and flow rates of all seven wells, was large compared to the range of extrapolated data, and there was no portion of any of the curves where the slope indicated complete laminar or turbulent flow.

Fig 9 shows an average back-pressure curve for 25 well tests in the Hugoton field. The tests were made on wells in good producing condition and the observed data were taken over an average range of flow rates from 18.9 to 57.5 pct of the average back-pressure potential.

The large black dot to the right of the average absolute potential shown on Fig 9 represents the average stabilized open flow of the 25 wells and was determined by Pitot tube

measurement while the wells flowed wide open to the atmosphere.

There was no apparent upward bending of the back-pressure curve of any of the 25 wells and the values of the absolute potentials are not too great by straight line extrapolation of the curves through calculated data points. The average slope of the 25 curves was 0.755. The minimum slope was 0.623 and the maximum, 0.950.

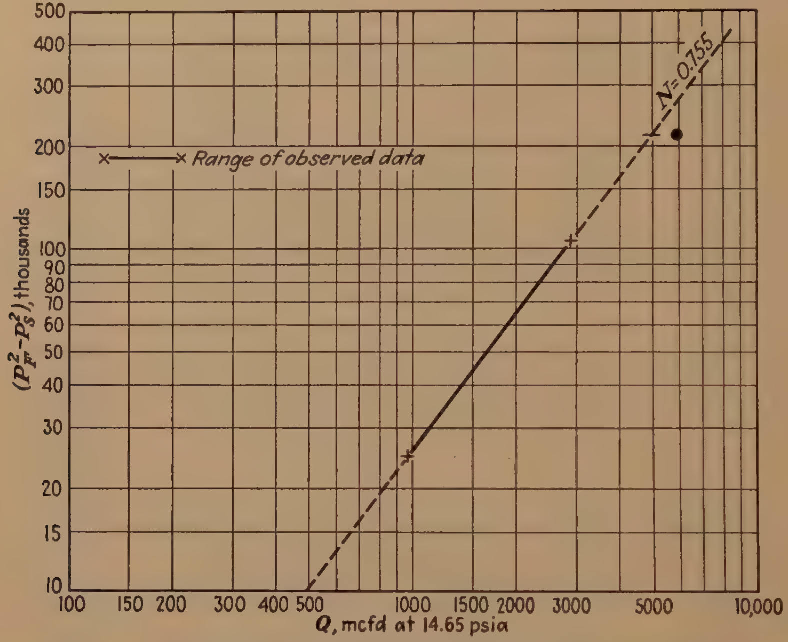

Fig 9—Back-pressure potential curve.

Average of 25 wells of Hugoton gas field. Shut-in pressure: 420.7 psig. Absolute potential: 5000 Mcfd. Observed open flow: 6200 Mcfd. First flow as percentage of potential: 18.9. Last flow as percentage of potential: 57.5.

It is possible that, in the actual case of the flow of gas from a producing formation into a well bore, the radii of turbulent and laminar flow both increase with increased flow rate in such a manner that the resulting back-pressure curve is a straight line throughout the range of combination flow. It is also possible that the flow of gas through permeable sand is not a combination of laminar and turbulent flow but is a type of tortuous flow controlled by the physical properties of the sand.

In view of present field experience further investigation and study appear necessary to determine whether back-pressure curves for normal gas wells are truly concave upward as described by Dr. Katz and Mr. Elenbaas.

In conclusion I wish to compliment the authors on their excellent paper. It is certain that the outlined procedures will stimulate further thought along the lines of the mechanics of gas flow through permeable formations.

D. D. Gillespie*—The end results of the work developed in this paper as are shown on Fig 7, the back-pressure curve of the hypothetical well, are quite interesting from an engineering standpoint. As shown by the curve, a straight line relationship between rate of flow and difference in the squares of the flowing and shut-in formation pressures does not exist. The existence of a line of changing slope rather than a straight line on this type plot has been indicated by a number of back-pressure tests which I have seen.

Since an average straight line relationship is

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universally used to show the relationship between flowing rate and the difference in the squares of the pressures, even though some actual tests and this paper show that the relationship has a changing slope, it is apparent that present work done in the lower rate ranges might be optimistic. It is indicated that estimates made for low rates against a constant low back pressure are undoubtedly over-estimated to some extent. This being the case, our estimates of recoverable reserves, which are determined by the minimum economic rate at which a well can be produced, are probably high and the life of a project is probably overestimated.

D. T. MacRoberts*—I was quite interested in observing the results obtained by Messrs. Elenbaas and Katz. They duplicate the observations I made some time ago using the Fancher and Lewis (ref. 4 of paper) data on flow through sands and graphically integrating the pressure gradient to determine a hypothetical back-pressure test. This hypothetical test shows the same characteristic curvature as that shown in Fig 7 of the Elenbaas and Katz paper. In both cases the low rates of flow at the transition point are rather surprising. In the sand I used the transition point occurred at approximately 1000 Mcf per day. It is more surprising that field data have not shown this result before now, and it appears that an experimental attack on the problem is worth while. However, an experimental project to verify this theory will be complicated by the transient behavior of the well to such an extent that it is doubtful that a clear corroboration can be obtained.

J. R. Elenbaas and D. L. Katz (authors' reply)—The original investigation on the flow of fluids through porous media was directed toward the solution of problems involved in rotary filtration. Therefore the publication in the *Chemical Engineering Progress* seemed more appropriate than in *Petroleum Technology*.

With regard to the use of the relationship for consolidated sandstones or limestones the data would not be available for making a direct calculation of the capacity of a well. However, we believe that the nature of the flow for conditions of comparable permeability would be very similar to that found in the nonconsolidated beds.

The curves presented by Mr. Binckley indicate that the curvature found in the example problem does not exist for the conditions of his tests. A primary difference between the two cases is the pressure level and permeability of the formation. It is quite possible that a curve of the curvature indicated in Fig 7 could be drawn through Mr. Binckley's data without deviating any more from his points than his straight line.

It was not the purpose of this paper to establish that back-pressure curves could be calculated without measurement of well characteristics but to indicate the nature of the back-pressure curve to be expected over a wide range of flow especially for high pressure wells.

Morris Muskat*—The authors have clearly illustrated the rather involved procedure required for determining the theoretical production capacity curves of gas wells when producing under turbulent flow conditions. In view of other comments on the practical significance of the authors' results, it may be well to confirm the theoretical necessity of their general conclusions in a slightly different manner. It can be readily verified that their general Eq 16 can be rewritten as:

$$\frac{\Delta P^2}{(\Delta P^2)_0} = \frac{\int_{\alpha W/r_e}^{\alpha W/r_w} f(\bar{R})\, d\bar{R}}{64 \log r_e/r_w} \qquad [20]$$

where ΔP^2 is the actual difference of the squares of the pressures, $(\Delta P^2)_0$ is that for the same system under strictly viscous flow, varying linearly with W, $\bar{R}$ the Reynolds number, $f(\bar{R})$ the friction factor, W the mass flow rate, r_w, r_e the well and external radii, and $\alpha = D/2\pi\mu h X^n$ in the notation of the paper. As $f(\bar{R})$ will exceed the viscous flow value, $64/\bar{R}$, whenever there is any turbulence at all, it is clear that the ratio on the left of Eq 20 will necessarily exceed 1, and cause a deviation in the ΔP^2 vs W curve such as shown in Fig 7 of the paper as soon as turbulence develops. And in the limit of complete turbulence, where f becomes constant, the right side becomes

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linear in W, as implied by Eq 19 of the paper. In fact, if f be approximated by:

$$f(\bar{R}) = \frac{64}{\bar{R}} + f_\infty \qquad [21]$$

Eq 20 becomes:

$$\frac{\Delta P^2}{(\Delta P^2)_0} = 1 + \frac{\alpha W f_\infty}{64 \log r_e/r_w}\left(\frac{1}{r_w} - \frac{1}{r_e}\right) \qquad [22]$$

which will give an essentially parabolic variation of ΔP^2 with W for the whole range of W. Finally it may be noted, incidentally, that if the form of Eq 20 be used, even with $f(\bar{R})$ considered as empirical, the evaluation of the ΔP^2 vs W curve requires only simple quadratures rather than trial and error procedures, provided the deviation factor of the gas and temperature be taken as constant.

Potentiometric-model Studies of Fluid Flow in Petroleum Reservoirs

By B. D. Lee*

(New York Meeting, March 1947)

Abstract

A simplification of the method of Hurst and McCarty for conducting potentiometric model studies by the single probe method is presented along with experimentally determined invasion patterns for certain idealized flow problems. The analytical solution for one class of these problems is given. Finally, a general description is given of a newly developed instrument which permits direct mapping of flow lines and determination of transit times in potentiometric-model studies.

Introduction

The object of this paper is to present:

1. A simplification of the method of Hurst and McCarty for conducting potentiometric-model studies of oil and gas reservoirs by the single probe method.
2. Results of a series of studies of certain idealized flow problems and the general conclusions to be drawn therefrom.
3. A description of a new instrument, the Chronocartograph, which greatly reduces the labor and time required for conducting potentiometric-model studies.

Certain general conclusions may be drawn as results of the investigation of the idealized flow problems. They are:

1. Injection and extraction areas should be separated by as great a distance as conditions permit since, in general, the recovery prior to first breakthrough tends to vary as the square of this distance.
2. Little advantage is to be gained by use of more than eight injection wells or groups of injection wells for the case of circular productive limits.
3. Elongated shapes of productive limits are best exploited by injection on the extended major axis only, with a line of extraction wells lying on the major axis.
4. The use of peripheral injection wells for elongated shapes is permissible, if necessary, but requires extension of the line of extraction wells.

The exploitation of an oil or gas field is effected either by the expansion of the gas and oil, or by their displacement by another fluid. Both methods may be used simultaneously. When the displacement of the oil or gas is the controlling factor there arises the problem of mapping the progress of the boundary between the fluid in place and the displacing fluid. This problem is of particular interest in the operation of a cycling project in a gas-condensate field, where the wet gas is produced from one or more wells, commonly called "extraction wells." This wet gas is taken into a processing plant where the condensate is removed. The remaining "dry" gas is injected back into the field through one or more wells, called "injection wells," both to conserve the gas for future use and also to maintain the pressure in the field. In an operation of this type it is essential to anticipate the manner in which the dry gas will spread through the field, because the ultimate recovery of the wet gas depends

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largely on keeping the dry gas from breaking into the extraction wells. It is thus necessary to know the shape of the boundary between the wet and the dry gas around the injection wells for various arrangements of wells and various injection and extraction rates so that a scheme can be selected which will postpone this break-through to the latest possible date. The above is equally applicable to water or gas drives, either natural or imposed.

Flow of Fluids through Porous Media

The laws governing the flow of fluids through porous media are well known. They are discussed in detail in Muskat's book.[1] Unfortunately, the mathematical solution of the problem previously outlined can be carried out only for certain idealized arrangements of injection and extraction wells, and then only for the simplest of boundary conditions. One class of these idealized problems will be examined later for the purpose of developing some basic principles which may be extended, at least qualitatively, to the more commonly encountered practical problems. The mathematical solution for the well arrangements and boundary conditions which actually occur is entirely impractical because of the excessive labor which would be involved. The only practical approach to these problems is through the use of models on a reduced scale. These models need not actually employ a porous medium and a fluid. As pointed out by Muskat,[1] there exists, under certain assumptions, an exact analogy between the flow of fluid in a porous medium and the flow of electrical current in a conducting body of similar geometry.

If one may make the following assumptions:

1. Permeability of the porous medium is uniform throughout the reservoir.

2. Relative permeability effects may be neglected.

3. The viscosity difference of the driven and driving fluids may be neglected.

4. Gravitational effects caused by differences in density of the two fluids may be neglected.

5. Compressibility of the fluids may be neglected. The electrical analogy of the hydraulic system may be established wherein electrical currents proportional to the injection and extraction rates are passed through the conducting body by means of electrodes at points corresponding to the positions of the wells in the field. Under such conditions, the potential distribution in the conductor is exactly analogous to the pressure distribution in the field and the current lines correspond exactly to the flow lines in the field. The study of fluid flow in an oil field is thus reduced to a study of current flow in an electrical conductor of suitable shape.

Such studies have been made in the past in metallic conductors, or graphite, but the conductor most commonly used is an electrolyte. Two methods are known for the mapping of a fluid interface by means of electrical models. The first of these, which has been applied very widely, is the "electrolytic model." This method is described by Muskat. The electrolytic model gives the desired results quite rapidly but with inferior accuracy, largely because of thermal diffusion of the ions, which results in loss of sharpness in the boundaries which are to be observed. Partly as a result of this loss of sharpness and partly as the result of other limitations which need not be discussed at this point, the electrolytic model is generally considered to give results of a qualitative nature only.

The second approach to the solution of the problem is through the use of an electrical conduction model. This model consists ordinarily of a conducting liquid, such as a solution of copper sulphate in water, in a pool the bottom of which is

[1] References are at the end of the paper.

shaped to correspond to the thickness of the oil or gas sand, and the periphery of which is shaped to correspond to the boundaries of the same sand. For practical reasons, the reduction in scale is much larger in the horizontal than in the vertical direction. At points corresponding to the location of the various wells in the field vertical metallic electrodes are introduced into the pool, usually through the bottom so as not to interfere with the measurements. Through these electrodes alternating currents of proper phase are passed into and out of the pool, the magnitude of the currents being proportional to the injection and extraction rates which it is proposed to employ. As already mentioned, the direction of the current flow at any point in the pool is then identical to the direction of fluid flowing at the corresponding point in the actual field, and the potential gradient at any point in the pool is proportional to the pressure gradient at the corresponding point in the field. Any element of fluid in the field follows a path corresponding to a current line in the pool. The transit time of an element of the fluid from one point to another is proportional to the line integral

$$\oint \frac{\partial x}{\partial p}\, dx \quad (p = \text{pressure})$$

taken along a flow line in the field, and hence it is proportional to the line integral

$$\oint \frac{\partial x}{\partial v}\, dx \quad (v = \text{voltage})$$

taken along a current line in the pool. The problem of mapping the progress of an interface between the driving and the driven fluids is essentially the problem of determining these integrals along all the current lines in the electrically conducting pool. The high precision with which a measurement of this type can be accomplished has been generally recognized. The method, however, has not been employed extensively because the means for obtaining the integral which is desired, as published in the literature, have been too laborious for practical application. There is one published instance of a study of this nature in a paper by Wm. Hurst and G. M. McCarty.[2]

The method employed by Hurst and McCarty consists of the following steps:

1. The system of equipotentials in the conducting model is mapped against a set of rectangular coordinates by means of a probe connected to a potentiometer.

2. The location of the equipotentials is plotted against a similar system of coordinates superimposed on a map of the field.

3. The current lines are constructed graphically by drawing a system of curves which intersect the equipotentials at right angles.

4. From the resulting map, step 3, a chart is plotted for *each* current line, showing the electrical potential as a function of distance along the current line.

5. Each curve resulting from step 4 is differentiated graphically and a new chart is plotted for each current line showing the derivative of length with respect to potential as a function of distance along the current line.

6. The area under each curve resulting from step 5 is integrated with a planimeter and a new curve is drawn for each current line showing this integral as a function of distance along the flow line. The ordinates of this last curve are proportional to the transit time between any two points read along the abscissa. This is the desired result.

It is clear that in any real problem the plotting and calculation of three separate curves for each current line is so time-consuming that either a large number of computers must be employed or the results cannot be obtained in a reasonable

time. This, no doubt, is the reason why, despite its accuracy, the method has not seen any extensive application.

Certain simplifications have been devised which make the application of potentiometric model studies quite practical. These consist of the following:

1. The first two steps of the Hurst and McCarty operation were reduced to one by the use of a pantograph swivelled at the center which carried the potentiometer probe at one end and a needle point at the other. With this pantograph the equipotentials may be plotted directly on the map of the field without the necessity of first reading the position of the equipotential points on a coordinate scale and then replotting these points. Instrumental details may be found by reference to Appendix II.

2. The drawing of the charts of steps 4, 5 and 6 for each current line was omitted altogether because it was recognized that the transit times along a flow line could be obtained from the difference equation

$$\Delta t \sim \frac{\Delta x}{\Delta v/\Delta x} \sim \frac{(\Delta x)^{2*}}{\Delta v} \qquad [1]$$

if Δx be taken sufficiently small. Moreover, if the ΔV's are all made the same in Eq 1, simply by constructing equipotentials which differ by a fixed amount, then

$$\Delta t \sim (\Delta x)^2$$

that is, the transit time between successive equipotentials is proportional to the square of the distance between these equipotentials. These transit times, then may be obtained by measuring this distance and squaring it. This was accomplished by the use of a special scale which read the square of the distance directly. In practice, the lengths which are involved are too small for a practical scale so they were enlarged with proportional dividers and the square scale was enlarged correspondingly. The readings of the square scale were then entered directly on each segment of a current line and the transit time of an element of fluid between any two points was obtained by a simple addition of the small time intervals along the short segments of the current line.

* This relationship was independently developed and used by Hurst and Van Everdingen.[3]

The procedure described above reduced the time required for a potentiometric study to a small fraction of the time required for the procedure described by Hurst and McCarty. A number of studies of this type were conducted by the simplified method. It was by use of this method that the study of certain idealized flow problems was undertaken by this writer.

Study of Certain Idealized Flow Problems

The purpose of these studies is to determine the swept-out area as a function of the number and position of injection wells having equal injection rates. Both circular and noncircular shapes of productive limits will be considered. One centrally located extraction well is used for the circular shapes with injection wells evenly spaced on a circle concentric with the productive limits. The number and position of extraction wells for noncircular shapes will be determined for optimum recovery.

The following assumptions are made in the discussion which follows: (1) the porous medium is limitless in all horizontal directions, is horizontal and of uniform thickness and permeability; (2) relative permeability effects may be neglected; (3) the viscosity difference of the driven and driving fluid may be neglected; (4) gravitational effects caused by differences in density of the two fluids may be neglected; (5) compressibility of the fluids may be neglected.

The problem may now be stated in the following form: find the manner in which

the time of the first breakthrough varies as the number and location of injection wells changes, injection rate being uniform for all wells. This may be done by either of two methods, (1) direct calculation; (2) experimental determination.

By direct calculation in the case of uniform circular distribution of injection wells with the extraction well at the center of the injection-well circle, and the injection-well circle lying wholly within the productive limits, it may be shown (see appendix I for proof) that the swept-out area, A, is a function only of the radius, X, of the injection-well circle and the number, n, of the injection wells.

$$A = \pi x^2 \frac{n}{n+2} \qquad X \lesseqgtr R$$

where R is the radius of the largest circle, with center at the extraction well, which may be inscribed within the productive limits.

It is interesting to note that, so long as the above conditions obtain, the shape of the productive limits has no effect on the area swept-out. Since A is proportional to the square of X, the swept-out area will increase rapidly as the radius of the injection-well circle is increased. Since A is also proportional to the ratio of (n) to $(n + 2)$, it is evident that a serious case of diminishing returns exists with increasing numbers of injection wells. A single well would sweep-out $1/3$ of the area of the injection-well circle; 2 wells, $1/2$, 3 wells, $3/5$; 4 wells, $2/3$; 8 wells, $8/10$; 12 wells $6/7$; and so on, with the maximum value when $n/(n + 2) = 1$, that is, when n is infinite.

In the case of a circular shape of productive limits of radius R with the extraction well at the center and injection wells with equal injection rates uniformly spaced on a circle of radius X, greater than R, concentric with the circle of productive limits, the swept-out area

$$A = \pi R^2 \left[1 - \frac{2}{n+2} \left(\frac{R}{x} \right)^n \right] \qquad X \gtreqless R$$

The expression $\pi R^2 \frac{2}{n+2} \left(\frac{R}{x} \right)^n$ is the unrecovered portion at first breakthrough and examination of its behavior as X and n vary, will determine the behavior of A. Remember that the ratio R/X is always less than unity.

In either of the above cases, it is evident that loss decreases quite rapidly as the radius of the injection-well circle or the number of injection wells increases and that recoveries approximating 100 pct may be obtained with reasonable values of X and n.

Fig 1 shows percentage recovery as a function of X/R for various values of n. Fig 2 shows percentage recovery as a function of n for various values of X/R. Fig 3 shows percentage loss as a function of n for various values of X/R. Fig 4 shows the increase in percentage recovery to be obtained by adding one injection well for various values of n and X/R. For example, at $n = 0$ the first added injection well results in an increase of 21 to 58 pct with a diminishing return for the addition of further injection wells. This figure illustrates very clearly the law of diminishing returns as the number of injection wells is increased.

Calculation of the recovery to the time of first breakthrough for shapes of productive limits which are noncircular when the injection-well circle lies partially or wholly outside of the productive limits requires determination of the time required for the driving fluid to reach the producing well (or one of them if there be more than one) along the shortest time path. In this connection it is desirable to introduce the concept of the family of isochron curves which center about the extraction well(s), each curve of the family passing through all points from which a particle will reach the extraction well (or one of the

wells if there be more than one) at a given time. Obviously, the swept-out area at a given time will equal the area included within the corresponding isochron. Thus the recovery which may be obtained from a given arrangement of wells is determined by that isochron which is tangent to the productive limits at some point but which does not cross the limits. The shape and included area of the various isochron curves is obviously dependent only on the well arrangement and extraction rate, and is wholly independent of the shape of the productive limits as long as the porous medium is unbounded. It is possible to calculate these isochrons

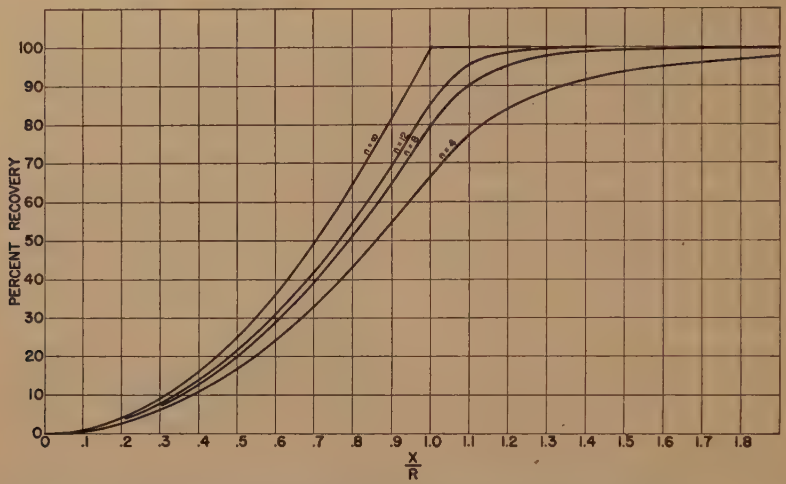

FIG 1—PERCENTAGE RECOVERY AS FUNCTION OF RATIO X/R.
X is radius of injection-well circle and R is radius of productive limits. The two circles are concentric. The number of injection wells is n.

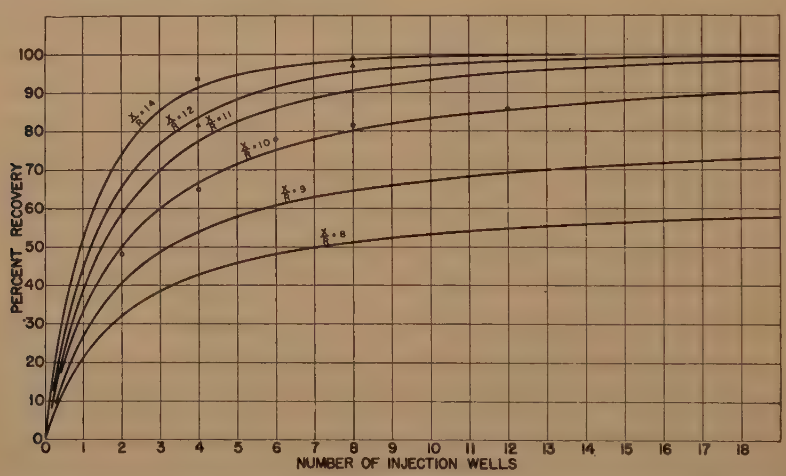

FIG 2—PERCENTAGE RECOVERY AS FUNCTION OF NUMBER OF INJECTION WELLS FOR VARIOUS VALUES OF RATIO X/R.
Conditions are as defined for Fig 1.

for the uniform circular distribution of injection wells with extraction at the center of the injection-well circle. Other arrangements are generally difficult of handling and are best determined experimentally.

mined for all segments of all flow lines, the position of a particle moving along a given flow line may be determined for any time by summation of the Δt's along the path. It is by this method that isochron

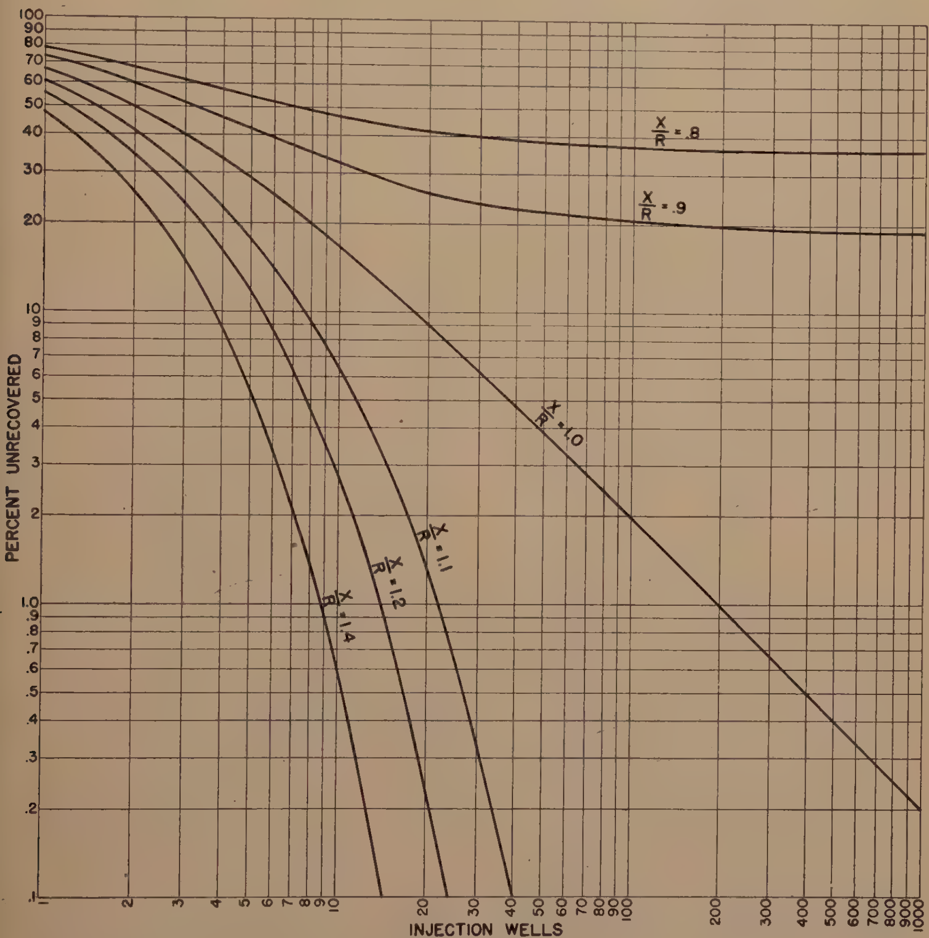

FIG 3—PERCENTAGE UNRECOVERED AS FUNCTION OF NUMBER OF INJECTION WELLS FOR VARIOUS VALUES OF X/R.

Using procedures outlined earlier for mapping equipotential lines and constructing current lines one may apply the difference equation

$$\Delta t \sim (\Delta x)^2/\Delta V$$

to obtain the Δt's along all the flow lines of interest. When times have been determined for all segments of all flow lines, ...

diagrams and shapes of swept-out areas are determined.

In all except very irregularly shaped models certain lines of symmetry will appear. It will suffice to map the segment between such lines and repeat the pattern as many times as required to fill the space in the plane. For example, with four

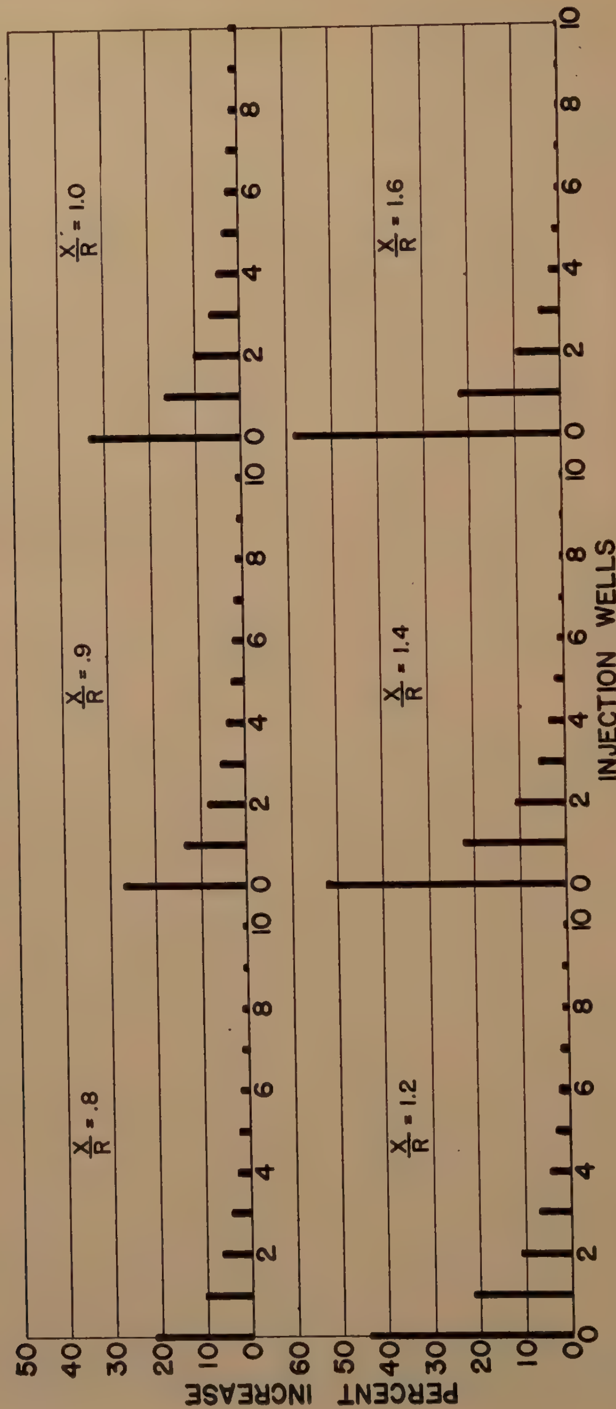

FIG 4—PERCENTAGE INCREASE IN RECOVERY FOR ONE ADDITIONAL INJECTION WELL AS FUNCTION OF NUMBER OF EXISTING INJECTION WELLS FOR VARIOUS RATIOS OF X/R.

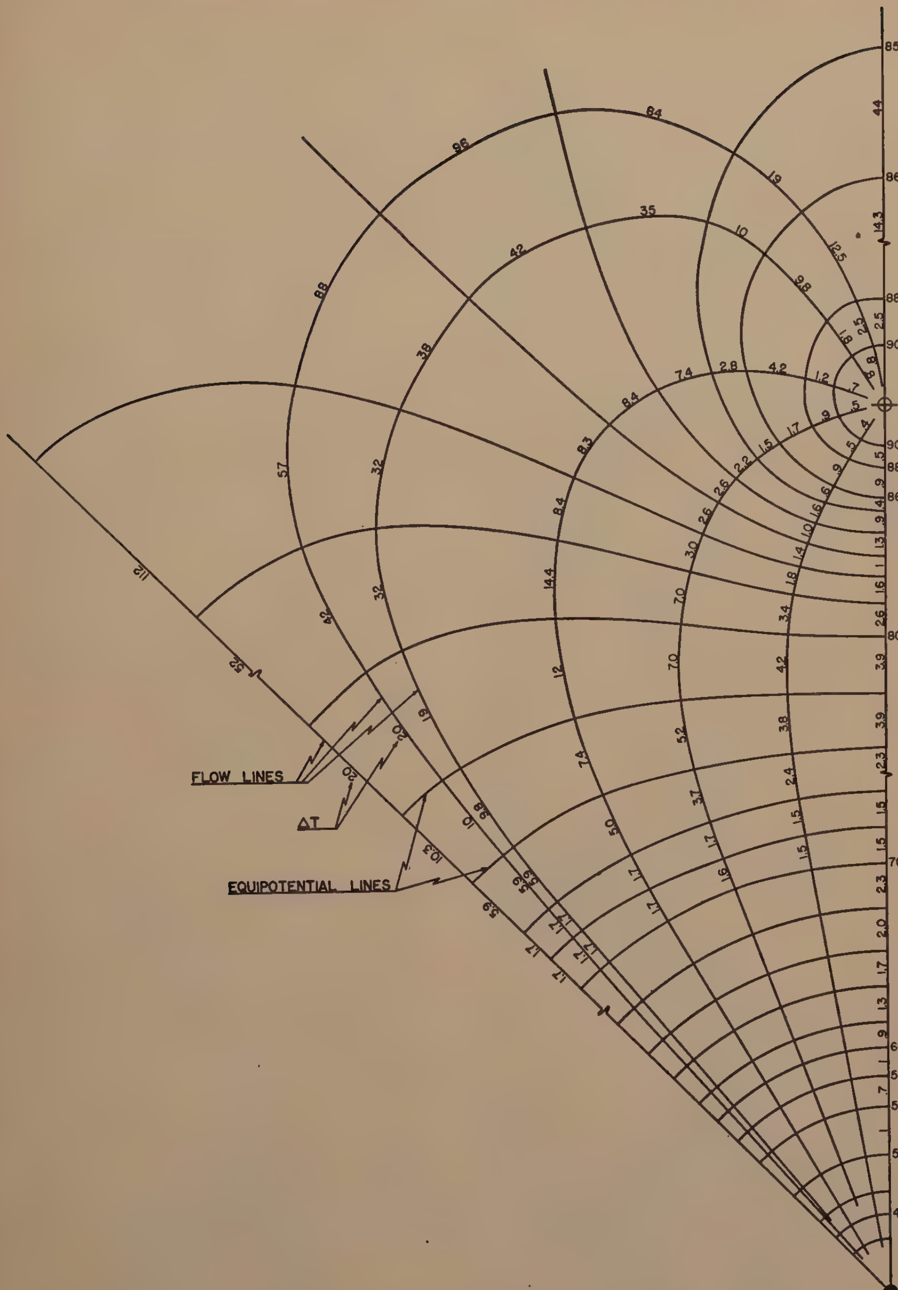

FIG 5—EXPERIMENTALLY DETERMINED EQUIPOTENTIAL AND FLOW LINE MAP FOR FOUR INJECTION-WELL SYSTEM.

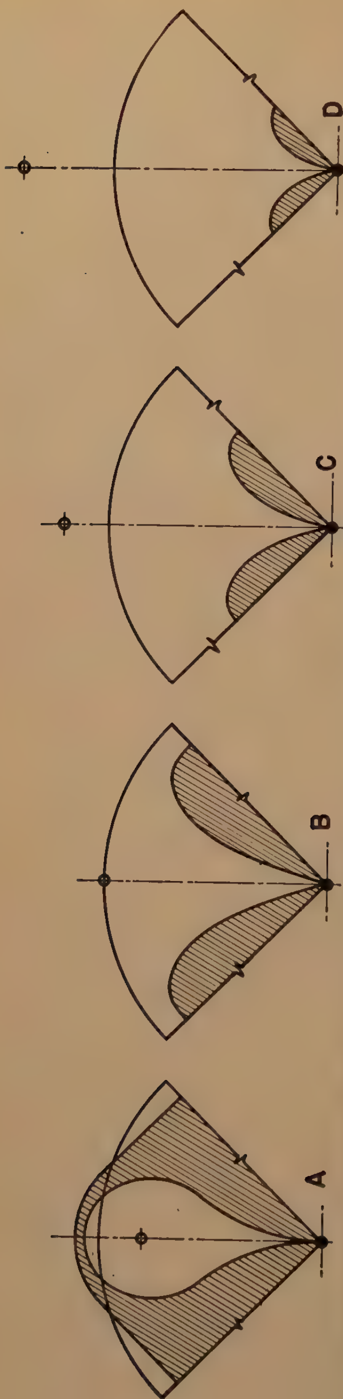

FIG 6—EXPERIMENTALLY DETERMINED INVASION PATTERNS FOR FOUR INJECTION-WELL SYSTEM FOR DIFFERENT POSITIONS OF INJECTION WELLS.
Shaded portion is unrecovered at time of first breakthrough.

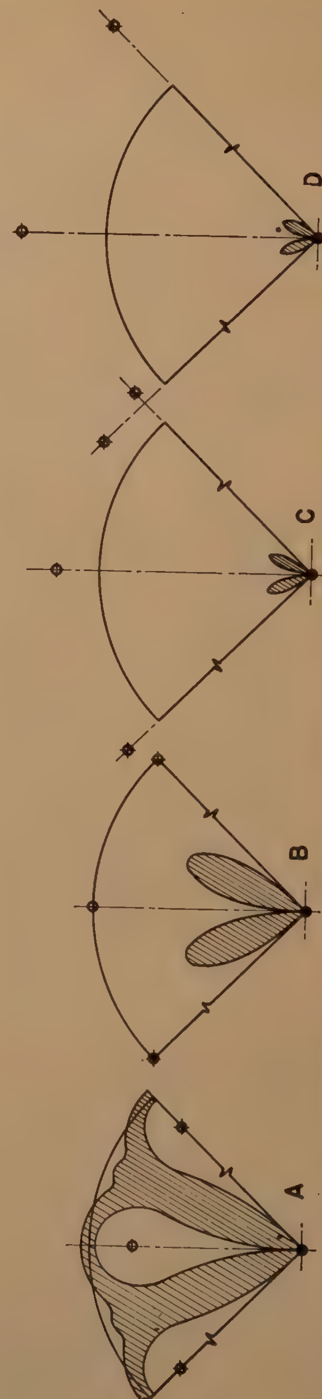

FIG 7—EXPERIMENTALLY DETERMINED INVASION PATTERNS FOR EIGHT INJECTION-WELL SYSTEM FOR VARIOUS POSITIONS OF INJECTION WELLS.
Shaded portion is unrecovered at time of first breakthrough.

equal rate injection wells on the circumference of a circle at whose center is located an extraction well, there are eight radial lines of symmetry: namely, the four radii passing through the injection wells and the four radii which bisect the space between the injection wells. Hence, the model for the problem need only include a 45° segment of the circle. Fig 5 shows the equipotentials and flow lines as mapped experimentally for the above problem. The transit times, determined as outlined, are written on each segment of each flow line.

With reference to Fig 5, it is obvious that the shortest time path from injection to extraction well lies along the radius joining the two wells. This is the time to first breakthrough. If each flow line is followed from the injection well until the summation of Δt's equals the first breakthrough time, the boundaries of the swept-out area may be determined at time of first breakthrough. Measurement of the area with a planimeter and multiplication by the number of such segments required to complete the space in the plane, eight, in this case, results in the total swept-out area to the time of first breakthrough.

Figs 6 and 7 show the experimentally determined swept-out areas for circular productive limits using various positions of four and eight injection wells. A comparison of experimental and calculated data is presented in Fig 2 where plotted points are experimental data. It may be noted again that shape of the productive limits is unimportant as long as the injection well circle lies wholly within the productive limits but that the shortest time path controls swept-out area in case the productive limits fall within the injection well circle.

As Muskat has shown on pages 571 and 572 of his book,[1] the area swept out to time of first breakthrough is a function of the geometry of the system and the rates of individual wells but is independent of direction of flow.

Reversing the direction of flow and determining the resulting fluid boundaries for various times up to the time of first breakthrough yields the isochron diagram for any particular well arrangement. Superposition of a scale drawing of the productive limits of any given shape of field on the isochron diagram for a particular well arrangement and determination of the time value of the ultimate isochron which remains wholly within the productive limits allows calculation of the maximum swept-out area to time of first breakthrough for that well arrangement. Let T be the transit time along the shortest time path from injection well to extraction well, t be the time value of the ultimate isochron which remains within the productive limits, A be the total swept-out area at time of first breakthrough for the well arrangement in question, and a be the swept-out area for the given productive limits and well arrangement. Then

$$a = t(A/T)$$

but (A/T) is a constant depending only on the well arrangement and the scale of the drawing. The equation may then be written

$$a = Ct$$

where C may be determined for each individual isochron diagram.

Figs 8, 9 and 10(A) show the experimentally determined isochron diagrams for various well arrangements.

The above outlined application of isochron diagrams is restricted only by the basic assumptions first set forth. There is, however, a class of fields which violates the assumption of continuity of the porous medium; namely, those fields in which an impermeable boundary is a part of the boundaries of the productive limits. In such cases, application of the

isochron diagram is possible when, and only when, the impermeable boundary may be made to coincide with a flow line of the particular well arrangement. being will be that area contained between the ultimate isochron and the impermeable boundary. The ultimate isochron, in this case, is the highest time-valued isochron

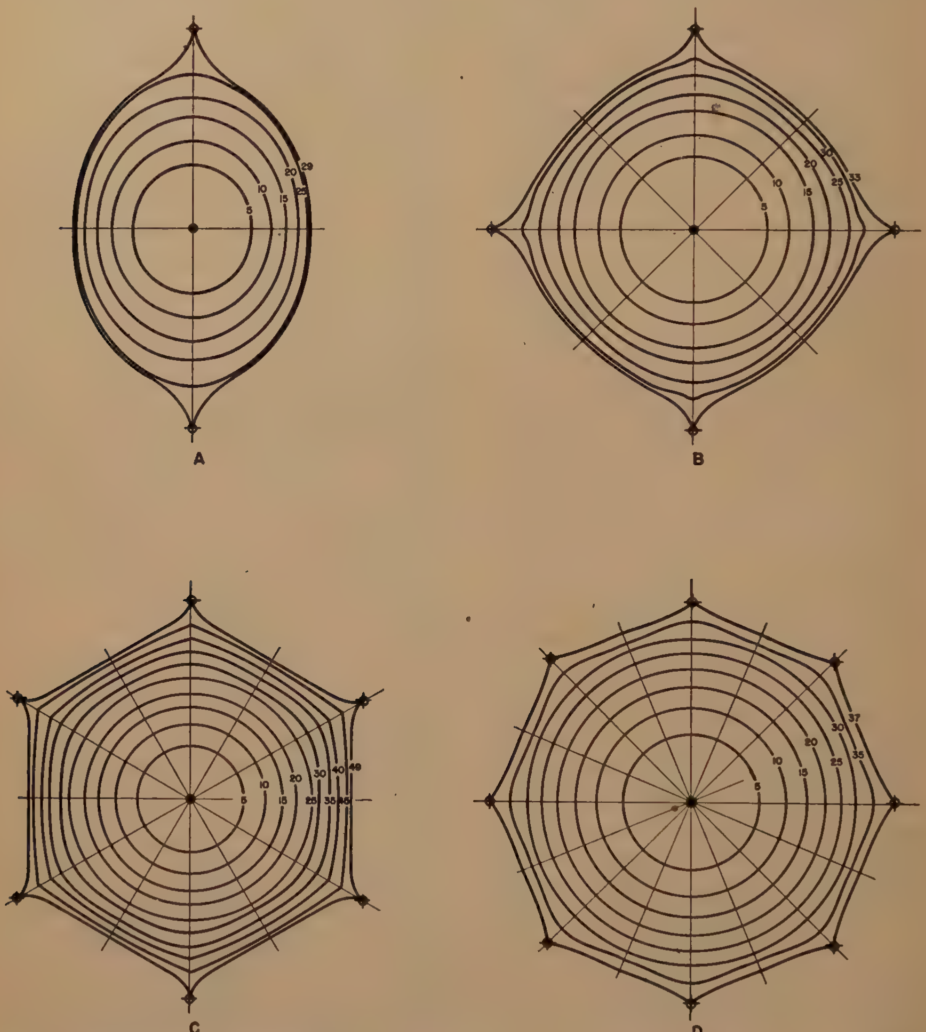

FIG 8—EXPERIMENTAL ISOCHRON DIAGRAMS FOR TWO, FOUR, SIX AND EIGHT INJECTION WELLS.

considered. Under these conditions only those wells lying on the productive side of the impermeable boundary contribute to production; the remainder of the wells may be omitted.

The swept-out area for such conditions which at no point crosses the productive limits in a permeable region but which may cross the impermeable boundary at will. Fig 10(B) illustrates the application of the isochron diagram to such a case. Note that only half the diagram is on the

productive side of the impermeable boundary (fault in this case) and that recovery is, therefore, $\frac{1}{2}Ct$.

Previous consideration of circular productive limits indicates that best recovery from a field will be obtained when the shape of the ultimate isochron coincides most nearly with the shape of the productive limits. Examination of isochron diagrams for circular distribution of injection wells with equal injection rates shows that the isochrons become more nearly circular as the number of injection wells increases. It is obvious that an infinite number of wells must produce a perfectly circular system of isochrons.

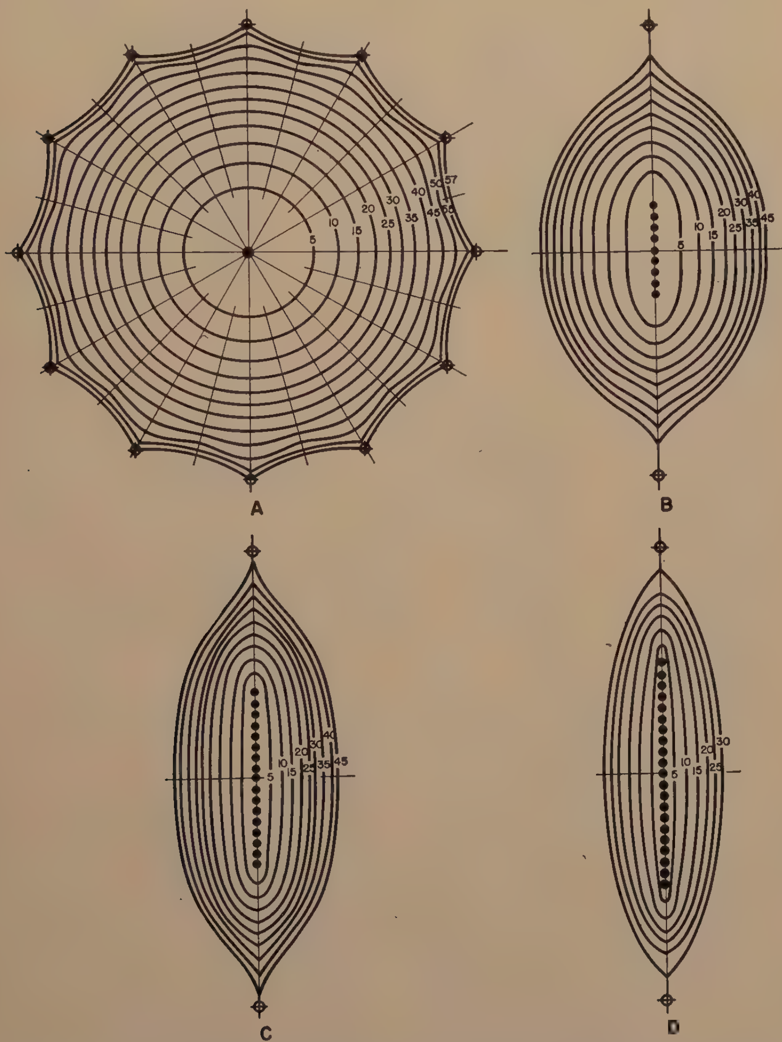

FIG 9—EXPERIMENTAL ISOCHRON DIAGRAMS.

A for twelve equally spaced injection wells. *B*, *C*, and *D* for two injection wells and various lengths of the line of extraction wells for use in the case of elongated productive limits.

It is equally obvious that improved recovery cannot be expected from a decidedly noncircular shape of productive limits by increasing the number of uniform complete recovery from an ellipse of the same proportions where the two injection wells are on opposite ends of the extended major axis a distance of 1.27 times the

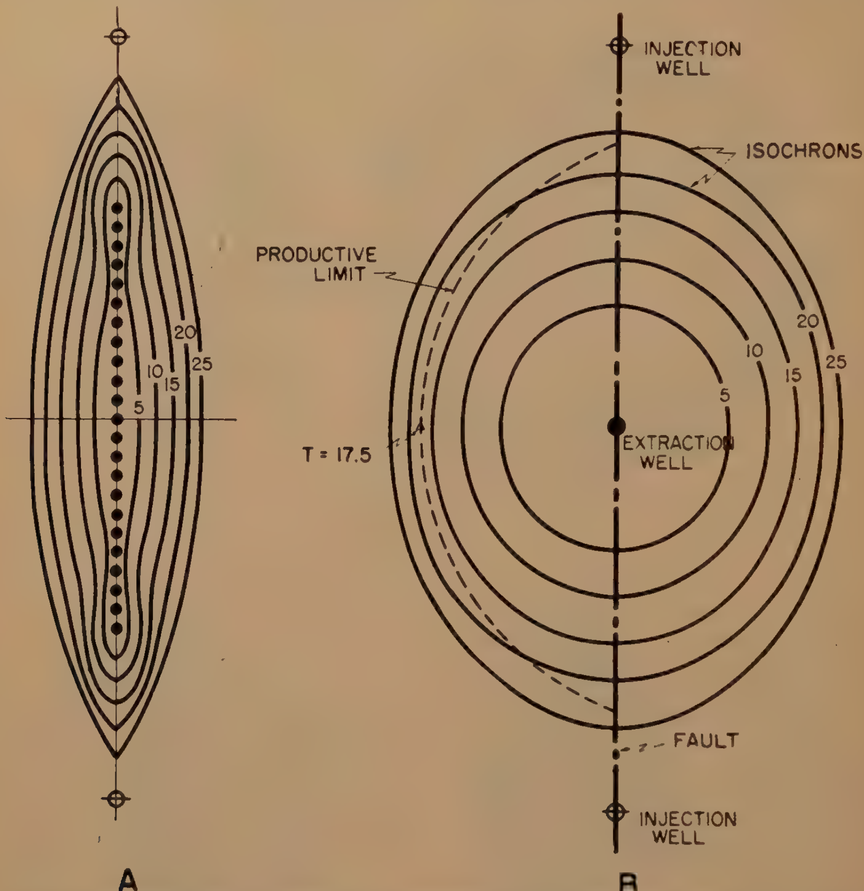

Fig 10(A)—Experimental isochron diagram for very long line of extraction wells. (B) Diagram showing application of an isochron diagram to a shape of productive limits involving an impermeable boundary.

rate injection wells on a circle. One would expect, rather, that recovery would decrease as the number of wells on the circle is increased. The isochrons for two injection wells have a definitely elliptical shape. The isochron for $t = 25$, Fig 8(A), has a ratio of major to minor axis of approximately 10:7. Such a well arrangement should, then, yield nearly length of the semi-major axis from the center of the ellipse with the extraction well at the center of the ellipse. Actually, better than 98 pct of such an ellipse can be swept-out by this arrangement. Had a four-injection well isochron diagram been used, the swept-out area would have been only 73 pct of area of the ellipse.

Figs 11 and 12 show experimental

results for various numbers and positions of injection wells for a 10:6 ellipse of productive limits using a single central extraction well. It is interesting to note that best results are obtained with only two major axis injection wells. The increase to four injection wells causes a decided reduction in recovery which is virtually independent of the position of the wells. Recovery remains substantially unchanged for eight wells and again their position has little effect. It is true that, in one case of two injection wells, Fig 11, it has been possible to secure simultaneous breakthrough along the major and minor axes, but note that the injection wells had to be placed within the productive limits in order to reduce transit time along the major axis.

Fig 13(A) shows the considerable improvement over Fig 11(A) which results from the use of a line of extraction wells disposed along the major axis.

Fig 13(B), (C) and (D) shows a 10:6 ellipse with 36 injection wells spaced 10° apart on the periphery of the ellipse for various lengths of the line of extraction wells. The best recovery occurs when the line of extraction wells covers approximately 55 pct of the major axis. For more elongated ellipses this line would have to be still longer. In the case of a large number of peripheral injection wells, a good approximation as to the required length of the line of extraction wells is obtained by terminating the line of extraction wells at the center of curvature of the ellipse at its intersection with the major axis. Inasmuch as many elongated figures may be approximated by an ellipse, the above reasoning may be extended to such figures.

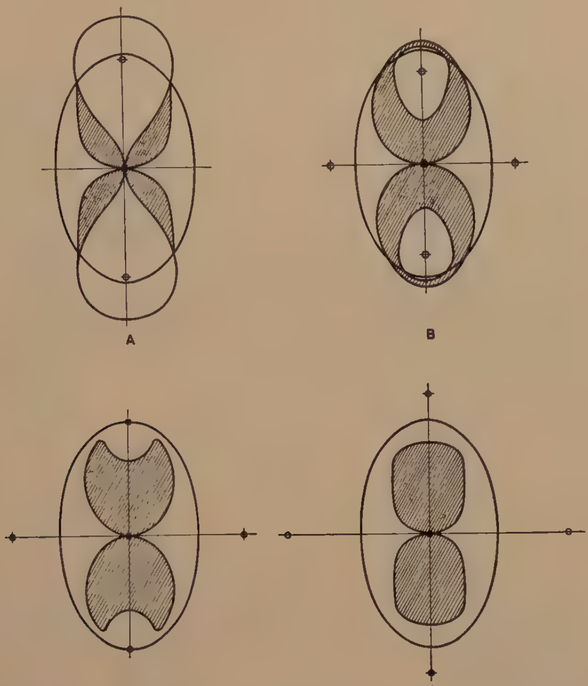

FIG 11—EXPERIMENTAL INVASION PATTERNS FOR 10/6 ELLIPTICAL PRODUCTIVE LIMITS FOR VARIOUS NUMBERS AND POSITIONS OF INJECTION WELLS.
Shaded area is unrecovered at time of first breakthroARY.

Development of the Chronocartograph

Up to this point, we have concerned ourselves with answering the question as to what recovery can be expected from a given arrangement of wells with equal rates applied to a reservoir of a given shape. In the practical application of the method of potentiometric-model studies to actual fields, a somewhat different problem is encountered. The problem, in general, is this: given a multiplicity of wells in an existing field, find that combination of injection and extraction wells and the individual rates for each which will result in the maximum attainable recovery from the field prior to the first breakthrough of driving fluid at an extraction well. The problem is usually complicated by the necessity of keeping injection and extraction rates within the physical capacities of the individual wells. Another complication frequently encountered is that some cycling program has usually been in operation for some

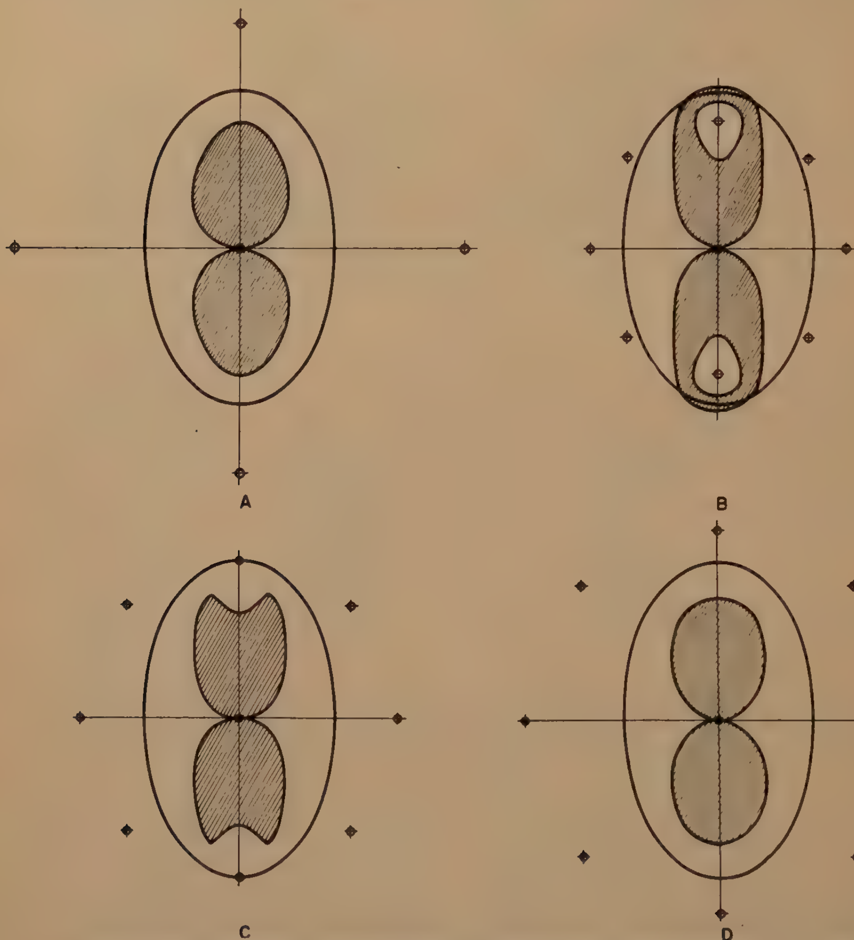

Fig 12—Experimental invasion patterns for 10/6 elliptical productive limits for various numbers and positions of injection wells.
Shaded area is unrecovered at time of first breakthrough.

time prior to the start of the model study. One is, thus, faced with the condition of a portion of the reservoir already being invaded by the driving fluid. Since set of rates. Finding the optimum is a process of cut-and-try. Any change of conditions necessitates a new study. A relatively large number of studies may be

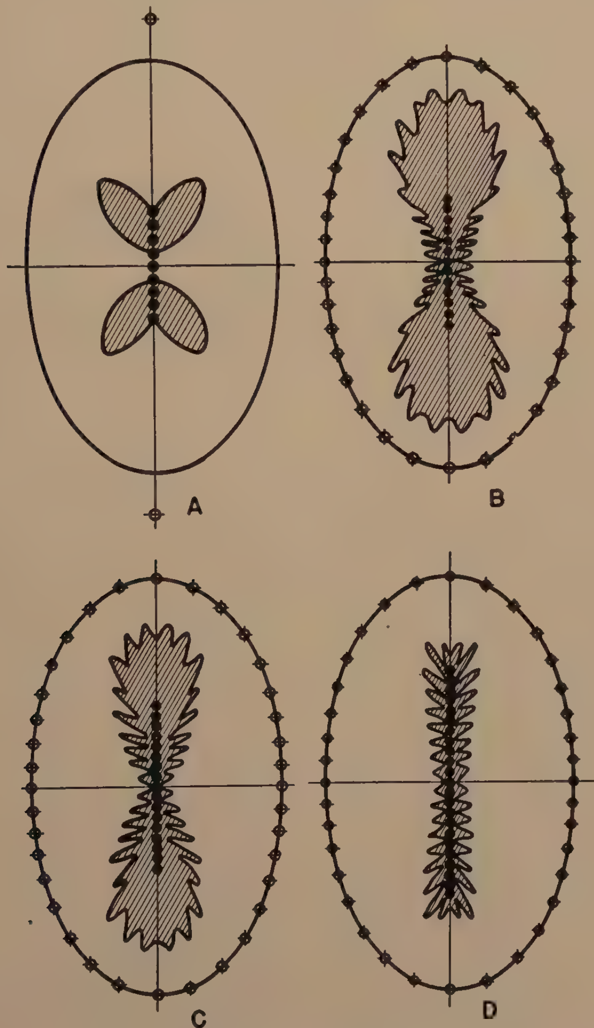

FIG 13—EXPERIMENTAL INVASION PATTERN.

(A)—Showing effect of line of extraction wells for 10/6 elliptical productive limits and two injection wells. (B, C, and D)—Effect of length of line of extraction wells in case of large number of peripheral injection wells. Shaded area is unrecovered at time of first breakthrough.

one cannot start over, the only thing to do is to make the best of the situation.

There is little chance of predicting beforehand what results may be obtained from a given arrangement of wells and required before one is satisfied that he has found the optimum. Each study involves a rather considerable amount of time, even by the simplified method, in mapping the potential distribution, con-

structing the flow lines, determining the incremental transit times along the flow lines, and, finally finding the boundaries of the invaded areas.

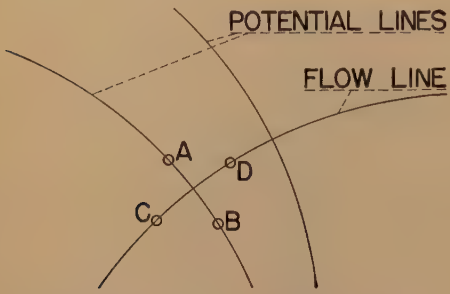

FIG 14—SKETCH SHOWING POSITION OF FOUR PROBE EXPLORING ARRAY AT BALANCE.

A and B are equipotential probes while C and D are flow line probes. The array rotates about an axis, normal to plane of drawing, through center of probe C.

In the process of running a number of practical studies by use of this method, it became apparent that a direct means of mapping flow lines and determining incremental transit times would be highly desirable from the standpoint of time saved. A method was devised for obtaining the desired results directly.

This method involved replacing the single probe of the potentiometer by a four-probe array, with the four probes placed on the legs of a right-angled cross as shown in Fig 14. These probes, constituting an "exploring foot," are placed in the conducting pool, and are mounted so that they swivel along the vertical axis through one of the probes, say C in Fig 14. If a null indicator is connected between probes A and B, and the entire array is rotated until this indicator registers zero voltage, probes A and B are then on points of equal potential. If the dimensions of the exploring array are small as compared to the dimensions of the model, it may be assumed that probes A and B are on an equipotential line. It follows, then, that probes C and D are on a current line since the line connecting C and D is at right angles to the line connecting A and B. A potentiometer connected between C and D reads the voltage difference between these two points. Referring back to the difference Eq 1,

$$\Delta t \sim (\Delta x)^2/\Delta V$$

it will be realized that in the system which is now described, all the Δx's are equal so that the transit time from C to D is proportional to the reciprocal of the voltage difference between these two points. The potentiometer connected between C and D can readily be so constructed and calibrated that the scale reads inverse voltage directly. Thus it reads a quantity proportional to transit time.

A mechanical support is provided which permits the exploring foot to be moved freely in a horizontal plane so as to occupy any desired position in the conducting pool. Means are provided for rotating the exploring foot around the vertical axis coinciding with probe C. This support further provides a transfer mechanism containing two pins, C′ and D′, with spacing equal to the separation between probes C and D which are rotationally interlocked to the exploring foot and so adjusted that the line joining these two pins is always parallel to the line joining probes C and D. These transfer pins permit the plotting of a current line in the conducting pool onto a map of the pool which has been properly oriented with respect to the pool.

Operation of the Instrument. After the model of the field has been constructed and the currents adjusted to the proper values, a map of the field is placed on the map table and properly oriented with respect to the model. The exploring foot is lowered into the conducting pool and probe C is placed at the desired starting point

which may be an injection well or a point on the boundary of a previously invaded area. The exploring foot is then rotated until probes A and B are on points of equal potential as shown by the null indicator. Probes C and D are then on a current line. The potentiometer connected to these probes is then adjusted to read the reciprocal of the voltage difference between these probes, that is, the transit time on an arbitrary scale. This reading is recorded and the position of transfer pins C′ and D′ are also recorded by punching the pins into the map. Pin C′ is then advanced to occupy the punch mark made by pin D′ on the previous operation. The system is again oriented, transit time determined, and the map marked by the transfer pins. A current line may thus be followed as far as desired by repetition of the above procedure. Total transit time from the starting point is obtained by a summation of the incremental times determined for each step.

The above steps may be accomplished manually with a minimum amount of equipment. It was found desirable, however, to replace the manual controls for orientation and potential measurement with suitable servo-mechanisms which accomplish these adjustments with as good, or better, accuracy as a human operator and have the further advantage that they do not tire of the monotony of repeating the operation as long as required. A totalizing device was also provided for the purpose of summing the incremental transit times corresponding to the segments of current line as the line is traced, and displaying this total to the operator.

In automatic operation of the instrument the operator is required only to select the starting point on the flow line to be followed, allow the servo-mechanisms to adjust themselves, mark the positions of the transfer pins which automatically actuates the totalizer to record that increment of transit time, and advance the exploring array to the next position.

The essential components of the Chronocartograph as used for automatic operation are:

1. A current control unit by means of which the currents to the various electrodes of the reservoir model may be adjusted.

2. A mechanical support for the four-probe exploring foot which permits free motion over the entire surface of the electrolyte of the reservoir model and further provides transfer of the position and angular rotation of the exploring foot to a flow map.

3. An amplifier connected so as to detect and amplify any voltage difference existing between the equipotential probes.

4. A phase sensitive reversible induction motor mounted on the mechanical support for the exploring foot so as to supply rotational force for orientation of the equipotential probes, receiving power from the amplifier (item 3).

5. A standard voltage source and potentiometer connected so as to compare the potential difference between the flow line probes with the standard voltage.

6. An amplifier connected so as to detect and amplify any unbalance voltage in the potentiometer circuit.

7. A phase sensitive reversible induction motor geared to the potentiometer shaft, receiving power from the amplifier (item 6), for the purpose of bringing the potentiometer to balance.

8. An indicator, coupled to the potentiometer shaft, calibrated to read the reciprocal of the voltage difference between the flow-line probes.

9. A totalizing device arranged to sum the incremental transit times corresponding to the segments of flow lines as the line is traced.

The instrument, as described above, has been successfully used on a large number of studies.

Acknowledgments

The author wishes to express his indebtedness to the cited works of Muskat and Hurst and McCarty for their formulation and reduction to experimental practice of this very powerful method of model studies. Also the writer wishes to thank the management of the Texas Company for permission to publish this paper, and to acknowledge the contributions made by various members of the Laboratory staff.

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Appendix 1

The Analytical Solution of Certain Flow Problems

The case of n line sources uniformly spaced around the circumference of a circle with a line sink at its center, all line sources being parallel and normal to the Z plane.

Any point in the W plane may be represented in complex notation as

$$W = p + iq = \rho\epsilon^{i\theta}$$

where $\rho = \sqrt{p^2 + q^2}$, and $\theta = \arctan \frac{p}{q}$.

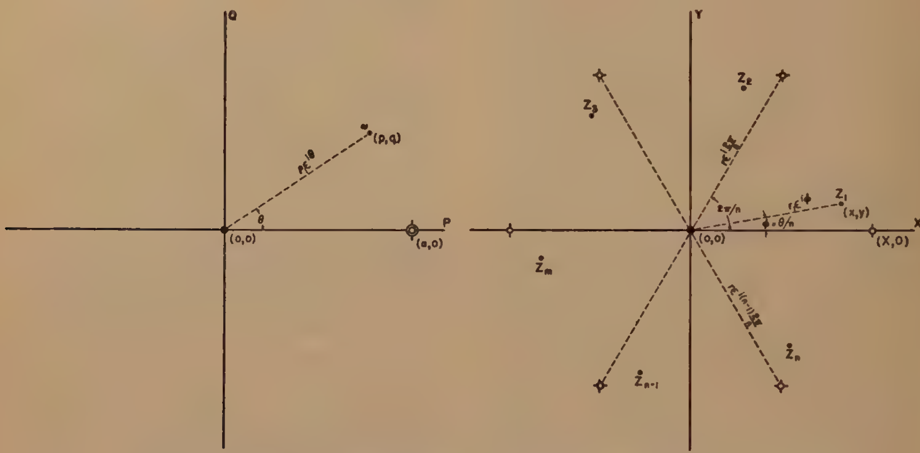

FIG 15—SKETCH SHOWING EFFECT OF TRANSFORMATION $W = Z^n$.
Where a single point in the W plane (left) is transformed into n points in the Z plane (right).

Let the transformation $W = Z^n$ or $W^{\frac{1}{n}} = Z$

$$Z = x + iy = r\epsilon^{i\phi}$$

be made. Then, $\rho\epsilon^{i\theta} = r^n\epsilon^{in\phi}$

$$\rho = r^n, \ \rho^{\frac{1}{n}} = r$$

$$\theta = n\phi, \ \frac{\theta}{n} = \phi$$

Reference to a text on the theory of complex functions will verify that this is a conformal transformation mapping the origin of the w plane onto the origin of the Z plane and converting any orthogonal system of lines in the W plane into a new orthogonal system in the Z plane except for a singularity at $Z = 0$. Any point in the W plane is transformed into n points in the Z plane all of which are equidistant from the origin in the Z

plane and separated by an angle of $\frac{2\pi}{n}$. This multiplicity of points arises from the fact that there are always n, nth roots of a complex function. For example, the four roots of unity are ϵ^{io}, $\epsilon^{i\frac{\pi}{2}}$, $\epsilon^{i\pi}$ and $\epsilon^{i\frac{3}{2}\pi}$, any one of which is unity when raised to the fourth power.

It is evident, then that this transformation converts the single source and sink in the W plane into n sources and a sink in the Z plane, see Fig 15, and that the orthogonal system of equipotentials and stream-lines of the W plane are transformed into an orthogonal system of equipotentials and stream-lines in the Z plane. The solution of the problem of n uniformly spaced sources on the circumference of a circle with a sink at the center of that circle is possible by such transformation.

Investigate the behavior of the potential distribution under this transformation. Reference to a text on functions of a complex variable will show that the potential distribution along the p axis of the W plane Fig 15, is

$$V = K \log \frac{p}{\alpha - p}, \quad q = o \qquad [1]$$

and the potential gradient is,

$$\frac{\partial V}{\partial p} = \frac{K\alpha}{p(\alpha - p)}$$

The transformed gradient in the Z plane when $y = o$ is

$$\frac{\partial V}{\partial x} = \frac{\partial V}{\partial p} \cdot \frac{\partial p}{\partial x}$$

When $q = o$ and $x = o$

$$p = x^n$$

and

$$\frac{\partial p}{\partial x} = nx^{n-1}$$

thus

$$\frac{\partial V}{\partial x} = \frac{nK\alpha x^{n-1}}{p(\alpha - p)}$$

Letting $\alpha = X^n$ the coordinates of the transformed source on the X axis being (X,O), and completing the substitution,

$$\frac{\partial V}{\partial x} = \frac{nKX^n x^{n-1}}{x^n(X^n - x^n)} = \frac{nKX^n}{x(X^n - x^n)} \qquad [2]$$

The transit time across the segment (a,O), (b,O) is

$$T_{ab} = \int_a^b \frac{dx}{\frac{\partial V}{\partial x}} = \frac{1}{nKX^n} \int_a^b x(X^n - x^n)dx$$

$$= \frac{1}{nK}\left[\frac{x^2}{2} - \frac{x^{n+2}}{(n+2)X^n}\right]_a^b \qquad [3]$$

When $a = o$ and $b = X$, the transit time

$$T_x = \frac{1}{nK}\left[\frac{X^2}{2} - \frac{X^2}{n+2}\right] = \frac{X^2}{2K(n+2)} \qquad [4]$$

Since the area swept out by an injection well is proportional to time, the area swept-out by a well to time of first breakthrough is,

$$A_1 = \frac{C'}{2K} \cdot \frac{X^2}{(n+2)}$$

and, there being n injection wells, the total swept-out area,

$$A_n = nA_1 = \frac{C'}{2K} \cdot \frac{n}{(n+2)} X^2$$

$$= C \frac{n}{n+2} X^2 \qquad [5]$$

where C is a constant to be determined.

As n approaches infinity the injection wells become a line drive coinciding with the circle of radius X whose center is the extraction well. Since every point on this circle is equidistant from the central extraction well and since every point on the circumference is an injection well, breakthrough will occur simultaneously from every point on the circle and the entire area will be swept-out at time of first breakthrough,

$$\text{limit}_{n \to \infty} A_n = \pi X^2$$

Hence $\pi X^2 = \text{limit}_{n\to\infty}\ C\frac{n}{n+2}X^2$

$$\text{limit}_{n\to\infty}\frac{n}{n+2} = 1, \text{ so that,}$$

$$CX^2 = \pi X^2$$

and,
$$C = \pi$$

Thus, C of Eq 5 is determined. Substituting the value of C into Eq 5,

$$A_n = \frac{n}{n+2}\pi X^2 \qquad [6]$$

Eq 6 is valid if the injection-well circle lies wholly within the productive limits regardless of the shape of those limits. If, however, the boundaries of the productive limits fall within the injection-well circle at any point, the shortest time path by which the driving fluid may reach the extraction well controls the recovery to time of first breakthrough. This may occur along any flow line. Hence such a problem requires evaluation of the time integral along that path. This integration can become quite difficult as it requires, first, the determination of the shortest time path.

Consider, however, the special case of circular production limits concentric with the injection well circle with the extraction well at the center, having a radius R less than, or equal to the radius, X, of the injection-well circle. In such a case, the time integral must be evaluated over the interval R instead of X.

$$T_R = \frac{1}{nKX^n}\int_0^R x(X^n - x^n)dx$$

$$T_R = \frac{1}{nK}\left[\frac{R^2}{2} - \frac{R^2}{n+2}\cdot\frac{R^n}{X^n}\right]$$

$$T_R = \frac{R^2}{2nK}\left[1 - \frac{2}{n+2}\left(\frac{R}{X}\right)^n\right]$$

The total area swept-out by the n wells is,

$$A_R = nC'T_R = CR^2\left[1 - \frac{2}{n+2}\left(\frac{R}{X}\right)^n\right]$$

but $C = \pi$, so,

$$A_R = \pi R^2\left[1 - \frac{2}{n+2}\left(\frac{R}{X}\right)^n\right] \qquad [7]$$

Appendix 2

Electrolytic Models

The model used in these experiments consisted of a wooden tank in the shape of a 90° circular segment with radius of 20 in. and depth of 1½ in. The interior of the tank was sealed off with a waterproof insulating varnish followed by a coat of wax. Movable radial bakelite partitions were provided so that angles less than 90° could be obtained to represent the conditions of larger numbers of injection wells. Electrodes, representing injection and extraction wells, were 1/10-in. diameter copper wire passing through the tank bottom. These electrodes were carefully sealed into the tank to prevent leakage of the electrolyte. Electrical connections to the electrodes were made on the under side of the tank bottom.

An electrolyte of relatively low conductivity is desirable in order to minimize the effect of contact resistance between electrodes and the electrolyte. The composition of the electrolyte was as follows:

Stock Solution:

15 grams copper sulphate (anhydrous)
5 grams sulphuric acid
5 grams ethyl alcohol
100 grams distilled water

This stock solution was diluted with distilled water in the ratio of 1 part stock solution to 50 parts of water.

In operation, it is important that the current in any electrode be kept low enough to avoid formation of gas bubbles on the electrodes. Formation of bubbles raises the contact resistance and causes a shift of equipotential lines. This shift causes increased experimental error if it occurs during the process of mapping the equipotentials. In these experiments, it

was found that currents of the order of 0.04 amp per electrode could be tolerated without appreciable effect from gas bubbling with an electrolyte depth of 1 in.

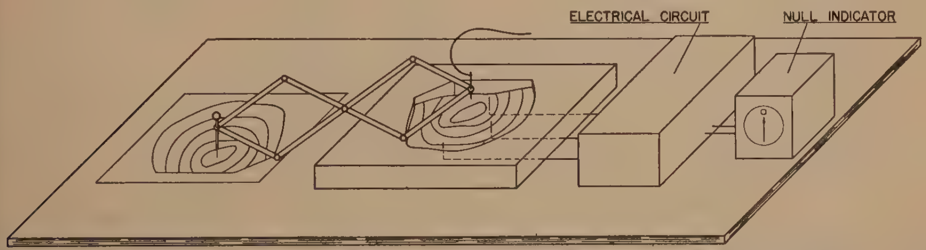

FIG 16—GENERALIZED SKETCH SHOWING SETUP FOR EQUIPOTENTIAL MAPPING WITH SINGLE PROBE METHOD.

Larger diameter electrodes or greater electrolyte depth will permit greater currents.

Current to the electrodes was supplied by a 1:1 isolation transformer from the 110 v 60-cycle power line. All electrodes representing injection wells were connected, through suitable resistors for each electrode, to one side of the transformer while all electrodes representing extraction wells were connected through a similar system of resistors, to the opposite side of the transformer winding. The currents, corresponding to injection or extraction rates, were then adjusted to the desired values. A potentiometer, consisting of two precision decade resistance boxes, was then connected between one injection and one extraction electrode. In practice, it is best to select those electrodes having the smallest potential drop in the series resistors connecting them to the transformer.

A probe, mounted on one end of a 1:1 pantograph, with its tip immersed in the electrolyte was used to explore the tank. This probe was connected to the input of a 60-cycle band-pass amplifier, the ground potential side of which was connected to the junction of the two decade resistance boxes. The sum of the resistances of the two boxes was maintained constant at 10,000 ohms. By adjusting the ratio of the two boxes, the potential of their common point was set at any desired percentage of the total voltage across the two boxes. The electrolyte was then explored to find the line which corresponds to this voltage. When the probe occupied a point on this equipotential line, the input to the amplifier was a minimum as indicated by a null on the galvanometer in the output of the amplifier. Barring pickup and phase shifts this minimum would have been zero but, practically, this was seldom realized. A null indicator, Fig 18, was substituted for the galvanometer. This device has the advantage of a threshold adjustment (grid bias on the 6E5 "magic eye") which may be set to remove the residual voltage effect when a minimum is reached. Having found a point on the desired equipotential line, a sharp prick-punch, mounted on the end of the pantograph opposite the probe, was depressed to mark the point on a sheet of paper. The probe was then moved to other null points, marking their position each time, until sufficient points had been obtained to permit construction of the equipotential line. This process was repeated for different settings of the ratio of the decade boxes until the required equipotential map had been obtained.

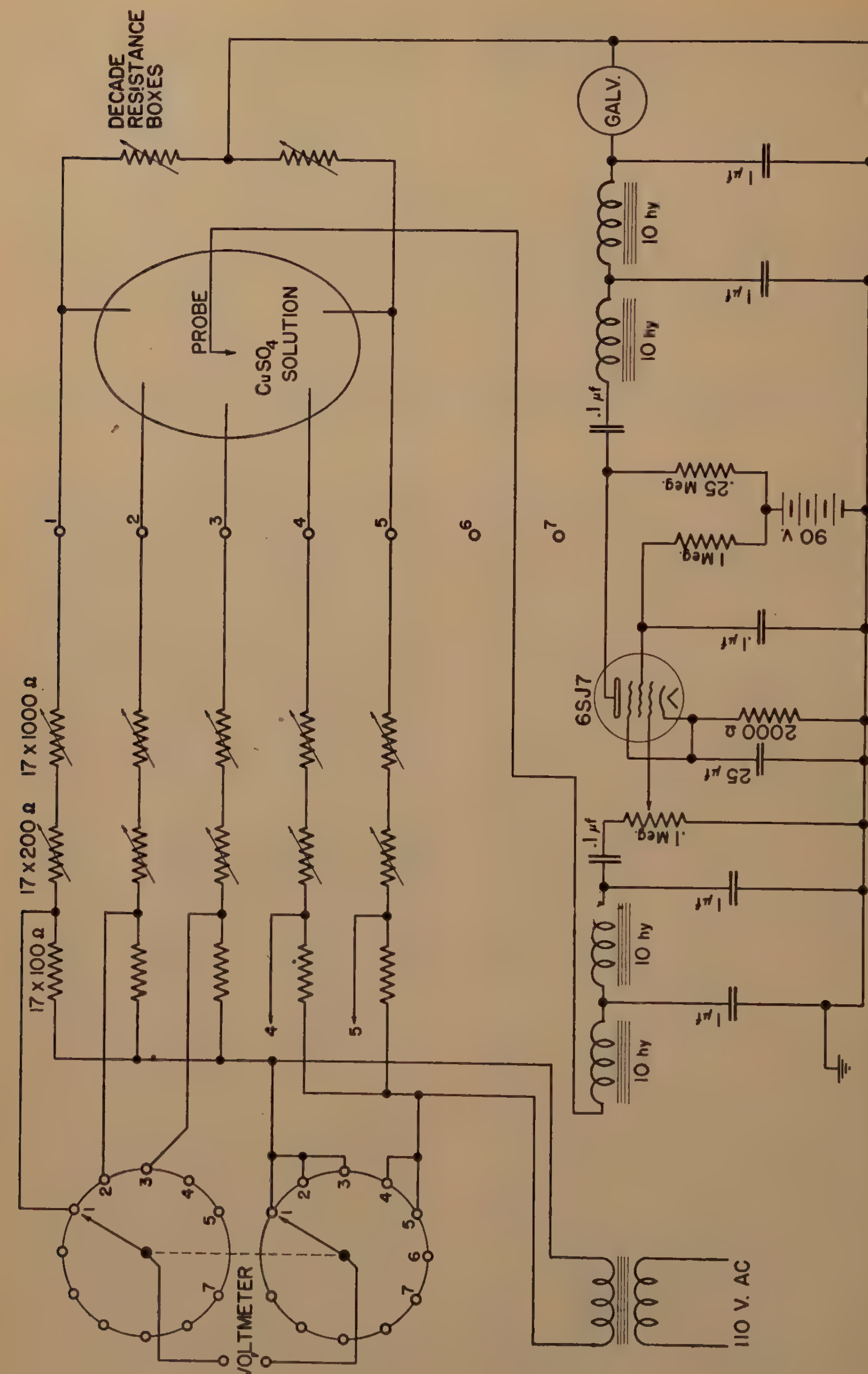

FIG 17—DIAGRAM OF ELECTRICAL CIRCUITS INVOLVED IN SINGLE PROBE EQUIPOTENTIAL MAPPING.

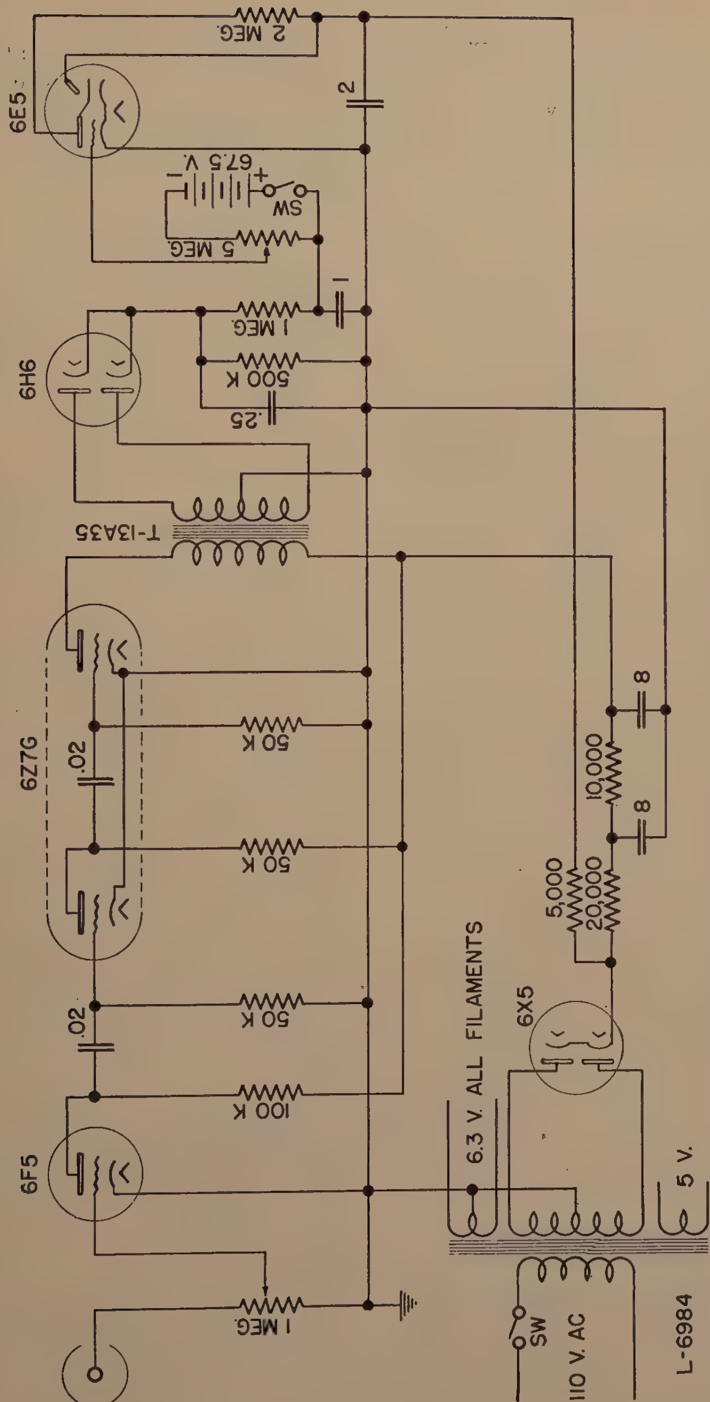

FIG 18—NULL INDICATOR WHICH MAY BE SUBSTITUTED FOR GALVANOMETER OF FIG 17.

The physical arrangement of the apparatus is indicated in Fig 16. Electrical details of the system are shown in Fig 17. The null indicator which was substituted for the galvanometer is shown in Fig 18.

Having obtained the equipotential map, it is necessary to construct the system of flow lines which are at all points normal to the equipotentials and then determine the transit times as explained in the text and illustrated in Fig 5.

Some Uses and Limitations of Model Studies in Cycling

By D. L. Marshall,* Junior Member, AIME and L. R. Oliver†

(New York Meeting, March 1947)

Abstract

The use of model studies for the development of invasion patterns for cycling is illustrated by model studies obtained with a recently developed apparatus in the solution of actual cycling problems.

Introduction

Depletion of a gas reservoir by cycling under pressure maintenance may be divided into three general phases. In the first phase, injection of dry gas is used to move all possible wet gas to producing wells prior to breakthrough of appreciable quantities of dry gas into producing wells. In the second phase, injection moves additional wet gas to producing wells while moderate quantities of dry gas are being produced. The third phase consists of production without injection to deplete the commercial gas reserve which remains after the cycling operation. Thus, in the first phase, a portion of the reservoir is invaded by dry gas, and the dry gas usually displaces something less than 100 pct of the wet gas from the invaded portions of the reservoir. The second phase enlarges the invaded portion of the reservoir and, at the same time, increases recovery from that zone invaded by dry gas in the first phase of the cycling operation. The result is an early yield of a substantial quantity of the liquefiable hydrocarbons in the reservoir with a minimum of the retrograde losses which occur in some reservoirs. The overall recovery from such an operation is usually high.

The summation of the paths taken by dry gas in a cycling operation can be termed an invasion pattern. The use of electrical models to predict invasion patterns has been the subject of several contributions to the literature.[1–3] The results of such model studies as applied to actual cases has been discussed by Kelton[4] and Miller and Lents.[5] Recently, an improved apparatus for conducting potentiometric model studies has been developed, as described by Lee.[6] The purpose of this paper is to present model studies or invasion patterns obtained with this instrument in the solution of actual cycling problems.

The percentage of displacement of wet gas within the invaded portion of the reservoir in cycling, increase in recoveries of wet gas by continuing cycling after dry gas breakthrough, recoveries of wet and dry gas by production after cycling, or economic factors in cycling are beyond the scope of this paper. Discussions which follow will be limited entirely to the development of suitable invasion patterns for cycling under pressure maintenance and the use of model studies therein.

Discussion of Results

In using model studies to predict invasion patterns in cycling, some factors which influence the results are the following:

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[1] References are at the end of the paper.

1. Configuration of the reservoir.

2. Pay thickness or space available to hydrocarbons as it varies from place to place in the reservoir.

3. Location and number of wells.

4. Well capacity, both injection and production.

5. Rate of production for the reservoir.

6. Time allowed for depletion, if cycling of a given reservoir is part of an integrated cycling program for a field containing multiple reservoirs.

The configuration of the reservoir may be considered to include the structural position, attitude, areal extent, and component parts of the reservoir, if there be more than one part. Some reservoirs, though continuous in fluid content, contain divisions resulting from variations in permeability, which divisions, although they may not be continuous, do, for the purpose of cycling, require separate cycling programs within the same reservoir, even though these separate programs might be parallel and simultaneous. Careful study of the reservoir to be cycled is required prior to the beginning of a cycling operation and thereafter continuously during the operation to determine as precisely as possible the configuration and behavior of the component parts of the reservoir and to coordinate the completion and operation of the wells to be used.

The variation of pay thickness or space available to hydrocarbons over the reservoir definitely influences the shape of the dry-gas front as it advances from injection well to producing well. Pay thickness is usually summarized on an isopach or net sand thickness map. Where sufficient data are available to show the variations in porosity and interstitial water an isovol map can be prepared to show the distribution of space available to hydrocarbons. This data is utilized in a model study through the use of a three-dimensional model which is constructed to scale from the isopach or isovol map which represents the reservoir being studied. If an isopach map is used average values of porosity and interstitial water must be applied to reduce invasion patterns to a time scale.

Depending on the state of development of the reservoir to be cycled, the location and number of wells to be used in cycling may be a variable or it may be entirely or partly fixed in the model study. The capacity of producing and injection wells influences the number of wells to be used in cycling. The proper location of wells is, however, of greater importance in influencing ultimate recovery.

The rate of production from a reservoir and the time required for its depletion are functions of various economic factors and, if cycling of a given reservoir is part of an integrated operation for several reservoirs, must be coordinated with the remaining parts of the operation.

In many instances, cycling of one reservoir is only one part of an integrated program for a field containing several cyclable reservoirs. The rate of production, location of wells and the time at which various wells are used in a given reservoir must then be chosen so as to fit integrated cycling of several reservoirs in series and possibly more than one in parallel and to fit the selected plant capacity. The desirable end, in this case is that: (1) maximum recovery may be had from all reservoirs; (2) all reservoirs may be depleted within a reasonable time and with the plant operating at capacity; (3) dry-gas production be minimized at all times; and (4) the best possible use be made of all wells and other facilities so as to realize maximum earnings.

Model studies are principally limited in their accuracy by the accuracy of the various physical factors which enter into formulation of any specific problem. The results of any study, at its best, can be expected to be only as good as the data which are used in it. Especially where a

single reservoir must be divided into several parallel cycling operations is the quantity of production from and injection into each component part of the reservoir particularly critical. In such instances, it is necessary at present to estimate the portion of injection into and production from each well applicable to each of the sections of the reservoir being cycled in parallel.

There follows a discussion of several case histories which will serve to present a general procedure which has been followed to select a desirable invasion pattern and several types of problems encountered. All model studies presented in these case histories were run using the Chronocartograph described by Lee.[6] All invasion patterns will be discussed without allowing for percentage displacement of wet gas within the invaded portions of the reservoir. Where available, displacement factors will be given; however, 80 pct is considered to be a fair average value.

Case Histories

Case "A"

To illustrate the evolution of a typical invasion pattern we have selected a gas-condensate reservoir from a multi-reservoir cycling program. To satisfy design capacity of the proposed cycling plant, and to comply with the capacity of other zones in this field, it was decided, after considerable testing, to produce Case "A" at a rate of 125 million cubic feet per day (MMcfd). Eleven wells were completed in this field when the decision to cycle the several reservoirs was reached. It was, of course, desirable that as many of the completed wells as possible should be used in the cycling program.

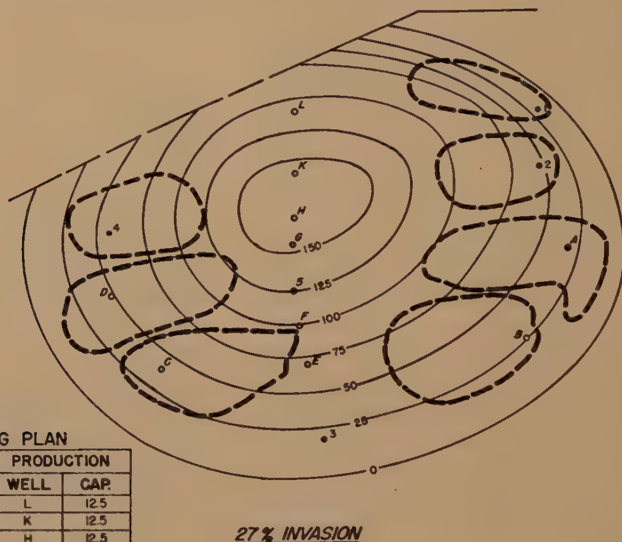
At the outset, it was assumed that the entire reservoir, as shown in Figs 1 and 6 was continuous and that there were no barriers such as bedding planes or shale beds which would prevent or restrict movement of dry gas across bedding planes. In other words, with reference to Fig 6, it was assumed that dry gas injected into wells 4 and "A" would invade the entire section above water in well "E."

There is a continuous gas-water contact across the reservoir. Therefore, in order to produce the desired volume of water-free gas, producing wells were required to be located on the crest of the structure and injection wells around the periphery. The tentative locations of new wells and utilization of existing wells were spotted on an isopach map (completed wells being designated by numbers and proposed wells by letters), and the initial model study was run with the total gas volume being equally distributed among the wells. The results of this study, shown on Fig 1, indicated the dry gas would break into the first producing well when approximately 27 pct of the volume was swept out.

This was unsatisfactory and in the next study the same locations were used as in Fig 1, but the rates were changed considerably and a more uniform front was obtained, resulting in a 63 pct invasion as shown in Fig 2. While this second study indicated a much greater recovery, the pattern was not satisfactory for two reasons: first, the rates were in excess of the permissible upper limit of production and, second, the dry-gas front from the west side reached the producing wells considerably in advance of the dry-gas front from the east side, leaving a substantial percentage of the wet gas between the east front and the producing wells unrecovered by the time dry gas broke in from the west side.

Fig 3 illustrates the third model study in which the same well locations were used as in Fig 1, the injection rates on the west side being reduced, those on the east side being increased, and production from the central line of wells being more evenly dis-

tributed to reduce the high rates of flow in the northernmost wells. This study resulted in a 72 pct invasion or 9 pct greater than the second study as shown in Fig 2. seven producing wells were used with the producing wells located in the area of greatest pay thickness. This study resulted in 67 pct invasion which was less than



OPERATING PLAN

INJECTION		PRODUCTION	
WELL	CAP.	WELL	CAP.
1	17.8	L	12.5
2	17.8	K	12.5
4	17.8	H	12.5
A	17.9	G	12.5
B	17.9	F	12.5
C	17.9	E	12.5
D	17.9	3	12.5
		5	12.5

NOTE: All capacities are in MMCFD.
Contours are net sand thickness in feet.

Fig 1—Case A. Problem No. 1.

While the dry-gas fronts from the east and west sides came closer to meeting at the line of producing wells before dry gas broke in from the west side, there was still a considerable area in the center of the field that was not swept out. Inasmuch as this area represents a considerable volume of the reserves it was felt that further study was necessary.

Well "C" was omitted in the next study, as shown in Fig 4, and well "D" was moved further south to compensate for its omission. To further increase the recovery from the center of the field, wells "E" and "F" were moved north of well 5, the southernmost producing well being converted from a producing to an injection well. Thus, seven injection and that of the previous study of 72 pct, but gave promise of greater invasion with further adjustment of locations and producing wells.

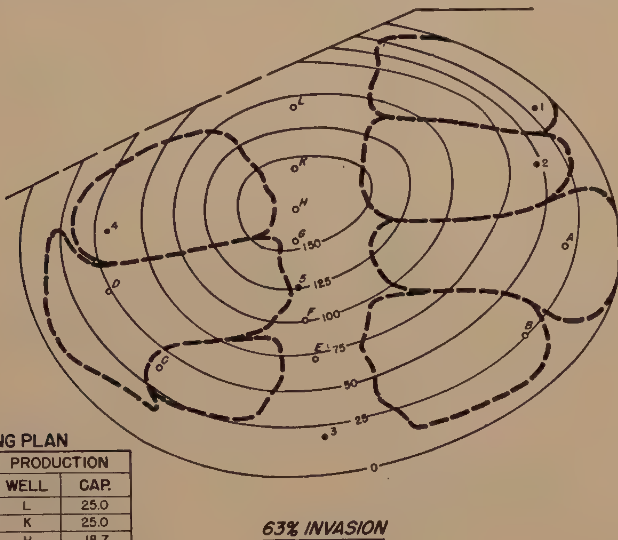
To increase the recovery over that of Fig 4, the proposed producing wells "E," "F," "G," "H," "K" and "L" were moved further north on the north-south axis and spaced closer together than as shown on the preceding study. Injection wells "A," "B" and "D" were moved further south as shown in Fig 5, and the rates were slightly changed from that of Fig 4, as a result of which 76 pct invasion was obtained.

Two factors, location of new wells and rates, can therefore be varied to increase the recovery. The proposed wells

"A," "B," "D," "E," "F," "G," "H," "K" and "L" were drilled at the locations shown and cycling was begun with the rates for the various wells shown on Fig 5.

Data obtained in drilling the additional wells indicated that the previous assumption of effective vertical continuity within the reservoir was not entirely correct, and that reservoir conditions were more nearly as schematically shown in Fig 6. As a result, it was suspected that the majority of the injected gas was confined to a very small section in the upper part of the reservoir. Dry gas could therefore be expected to break through into the producing wells in this thin section (zone A, section 1). To correct this situation, five injection wells were recompleted below water so that dry gas could enter all of zone A in all injection wells.

Injection below water had not, to the writers' knowledge, been used in earlier cycling operations but successful recompletion of these wells and subsequent injection of dry gas into a water-bearing sand offered no apparent obstacles. All of the injection wells were completed through 7-in. od casing which, in every well, extends to a deeper sand. It was necessary to gravel pack the underwater injection wells so that they could produce salt water to successfully clean the well bore and perforations of mud and other material. This was the only change necessary in the completion of injection wells below salt water as compared to injection wells completed in the gas pay section of the reservoir. To date this practice is still used in the completion of injection wells below salt water and no serious problems have occurred which would tend to condemn this practice.



OPERATING PLAN

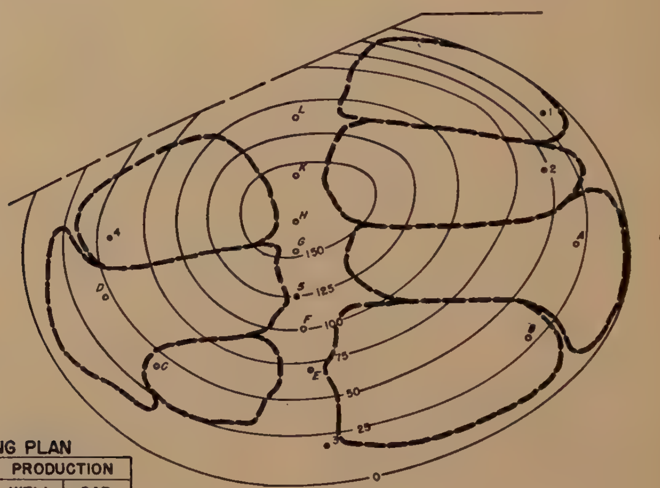
INJECTION		PRODUCTION	
WELL	CAP.	WELL	CAP.
1	9.0	L	25.0
2	25.0	K	25.0
4	25.0	H	18.7
A	20.0	G	18.8
B	14.0	F	10.0
C	7.0	E	10.0
D	25.0	3	5.0
		5	12.5

NOTE: Capacities are in MMCFD.
Contours are net sand thickness in feet.

FIG 2—CASE A. PROBLEM NO. 2.

With data obtained from the drilling

of the proposed wells in Fig 5 and new wells drilled to deeper reservoirs, it was necessary to make several changes in the mapping of the reservoir used in the which parallel cycling operations were being conducted. Accordingly, isovol maps of zone A, section 1 and zone A, section 2 were prepared for model studies of these



OPERATING PLAN

INJECTION		PRODUCTION	
WELL	CAP.	WELL	CAP.
1	10.2	L	23.8
2	28.3	K	17.5
4	21.1	H	17.5
A	22.6	G	18.7
B	15.9	F	12.6
C	5.9	E	12.5
D	21.1	3	6.1
		5	16.3

72% INVASION

NOTE: Capacities are in MMCFD.
Contours are net sand thickness in feet.

Fig 3—Case A. Problem No. 3.

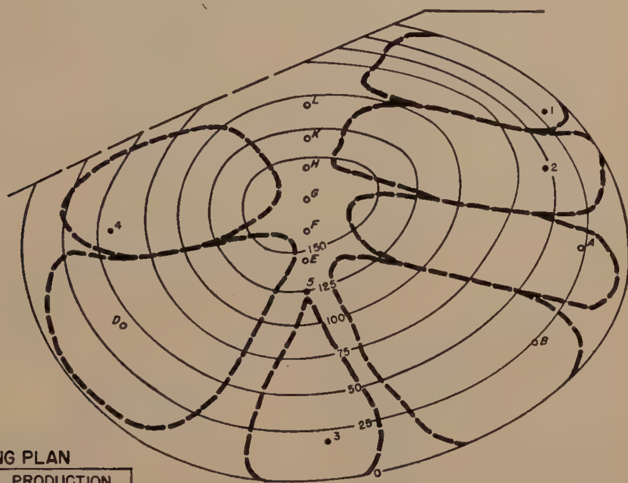
original model studies. The drilling of well "R," an exploratory well to outline the limits of the reservoir, made it necessary to change the position of the fault in the northwest portion of the structure. Shifting this fault northward appreciably increased the reserves. It was felt that well 4 would not efficiently sweep out the northwest portion of the reservoir; therefore, well "R" was used for underwater injection in an attempt to increase the recovery in that area.

After two years of operation, dry gas had appeared in wells 5, "E" and "F." The data accumulated was now sufficient to allow the preparation of isovol maps of the respective parts of the reservoir in two sections. While several producing wells were completed in zone B of this reservoir, none of the injection wells were perforated deeper than zone A. In the absence of an instrument to measure the amount of gas being injected into section 1 or section 2 of zone A in the injection wells and the production from section 1 and section 2 of zone A and zone B of the producing wells, it was necessary to estimate the amount of injection and production from the various members. Production and injection volumes were allocated on a capacity basis, that is, permeability of the section times thickness. With this method of allocating volumes, model studies were run on zone A, section 1

and zone A, section 2 and the results are shown on Figs 7 and 8. The invasion pattern for zone A, section 1, shown in Fig 7 illustrates the estimated position of dry gas after two years of operation. The results thus obtained duplicate the production history.

The model study shown on Fig 8, zone A, section 2, indicates the estimated position of the dry-gas front one year and nine months after the cycling program was initiated, and three months prior to that of the pattern shown in Fig 7, zone A, section 1. From these studies it was indicated that the dry-gas front in zone A, section 1, had swept out 57 pct of zone A, section 1, while that of zone A, section 2, was considerably retarded.

When dry gas from zone A, section 1 broke into the producing wells as mentioned above, injection wells "A" and "D" were reworked, and zone A, section 1 was squeezed off, confining all injection to zone A, section 2. Cycling was then continued until dry gas from zone A, section 2 broke through into the producing wells "F" and "E." It then became necessary to rework the producing wells "F" and "E," and drill-stem tests indicated that both sections 1 and 2 of zone A were relatively dry. These sections were squeezed off in the wells, and production now is derived entirely from zone B in wells "E" and "F." Thus the cycling of sections 1 and 2 of zone A are well under way and the next step in the development of this reservoir is the cycling of zone B.



67% INVASION

OPERATING PLAN

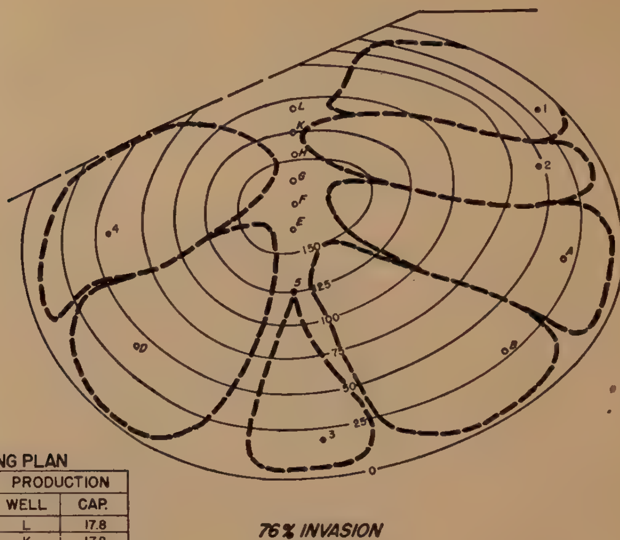
INJECTION		PRODUCTION	
WELL	CAP.	WELL	CAP.
1	7.0	L	17.8
2	22.0	K	17.8
3	8.0	H	17.8
4	22.0	G	17.9
A	22.0	F	17.9
B	22.0	E	17.9
D	22.0	5	17.9

NOTE: Capacities are in MMCFD.
Contours are net sand thickness in feet.

FIG 4—CASE A. PROBLEM NO. 4.

Case "B"

A slightly different type of problem is that presented by case "B." The reservoir is roughly elliptical and is completely underlain by water, but is too small to justify injection around the periphery and



OPERATING PLAN

INJECTION		PRODUCTION	
WELL	CAP.	WELL	CAP.
1	9.0	L	17.8
2	22.0	K	17.8
3	6.0	H	17.8
4	22[illegible]	G	17.9
A	22.0	F	17.9
B	22.0	E	17.9
D	22.0	5	17.9

NOTE: Capacities are in MMCFD.
Contours are net sand thickness in feet.

FIG 5—CASE A. PROBLEM NO. 5.

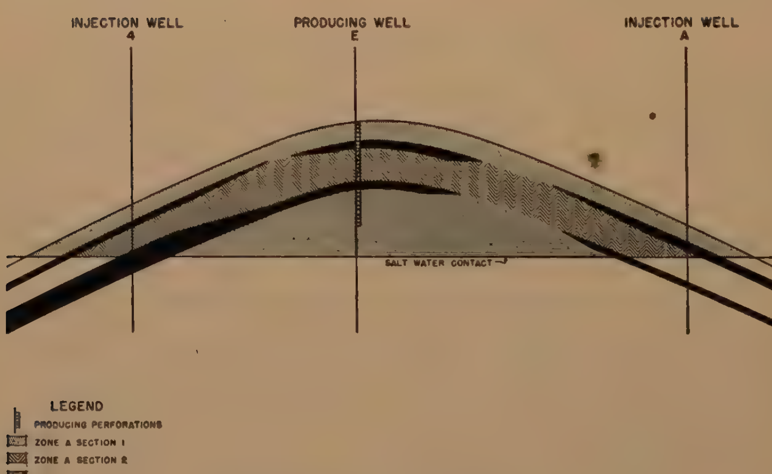


FIG 6—CASE A. CROSS SECTION.

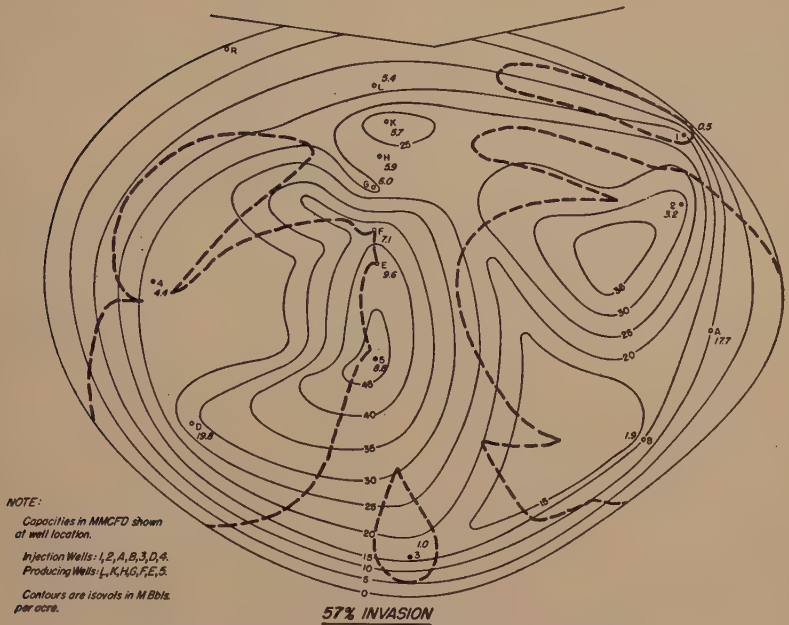


FIG 7—CASE A. PROBLEM NO. 6. ZONE A—SECTION 1.

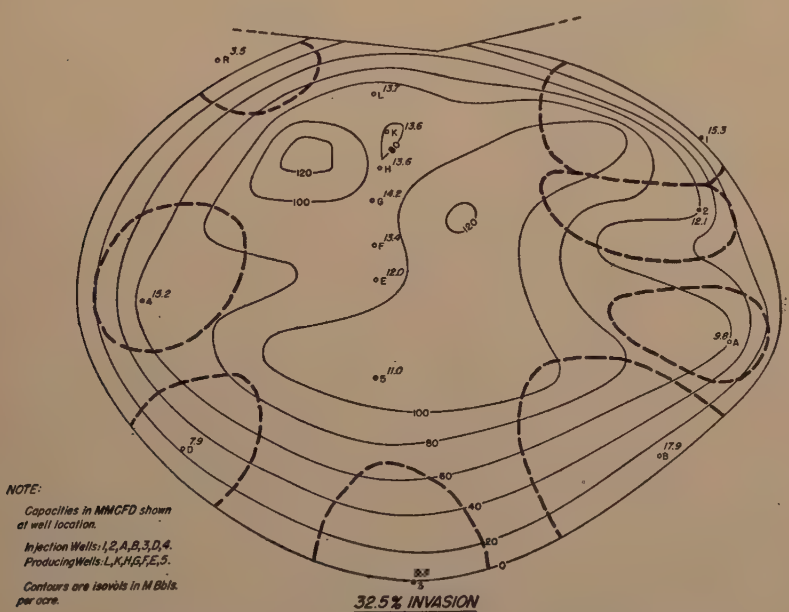


FIG 8—CASE A. PROBLEM NO. 7. ZONE A—SECTION 2.

production at the crest of the reservoir. The desired rate of production from this reservoir is 15.5 MMcfd.

The information available from wells rates. This invasion pattern differs from that of case "A" in that injection is in one end of the ellipse and production is from a line of wells at the other end.

69 % INVASION

OPERATING PLAN

WELL	CAPACITY & USE
M	15.5 INJ.
N	5.2 PROD.
9	5.2 PROD.
O	5.1 PROD.

NOTE: Capacities are in MMCFD.
Contours are net sand thickness in feet.

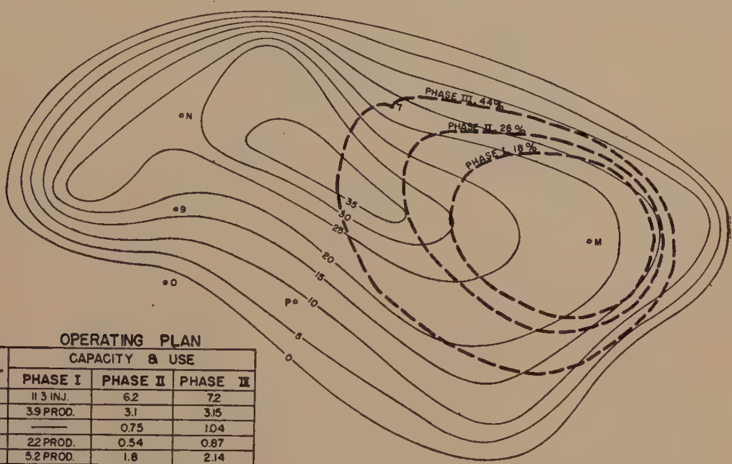
FIG 9—CASE B. PROBLEM NO. 1.

completed in the field was used to prepare an isopach map, and model studies were run to determine well locations and a tentative invasion pattern. This original study is illustrated in Fig 9. In this program only one well (No. 9) already completed was utilized, and it required the drilling of two producing wells "N" and "O" and the injection well "M." The individual well producing rate, as determined from well 9, was set at approximately 5 MMcfd, and it was assumed that the injection rate into well "M" would be sufficient to balance withdrawal

The first and only model study run on the original isopach (Fig 9) indicated that the cycling pattern, with 69 pct invasion, was satisfactory for an initial study, and the wells "M," "N" and "O" were drilled as indicated. During the interval between the initial model study and the start of cycling operations, well 7, drilled to a deeper reservoir, could not be used in that reservoir because of mechanical difficulties and was used in the case "B" program. This well (No. 7, see Fig 10) is in the north central portion of the reservoir, and inasmuch as it

appeared that the dry-gas front should be moved northward, it was completed in this reservoir as a producing well for this purpose.

Due to the thinning of the pay in the southwest portion of the reservoir, the producing well "O" was not capable of producing at rates set forth by the original model study. While well "O" was produced at limited rates for two years, it had to be abandoned because of water production, after approximately two years of cycling. It was believed that the deficiency of production in the southwest portion of the reservoir would appreciably reduce the invasion in this area and well "P" (see Fig 10), a well drilled to deplete a deeper reservoir, was completed in this

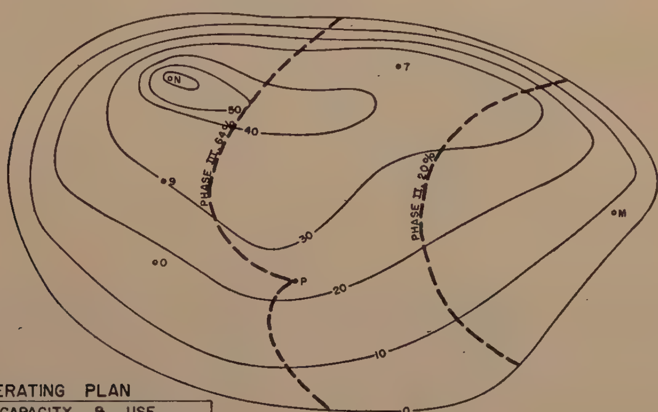


OPERATING PLAN

WELL	CAPACITY & USE		
	PHASE I	PHASE II	PHASE III
M	11.3 INJ.	6.2	7.2
7	3.9 PROD.	3.1	3.15
P	——	0.75	1.04
9	2.2 PROD.	0.54	0.87
N	5.2 PROD.	1.8	2.14

NOTE: Capacities are in MMCFD.
Contours are isovols in M Bbls. per acre.

FIG 10—CASE B. PROBLEM NO. 2. SECTION 1.



OPERATING PLAN

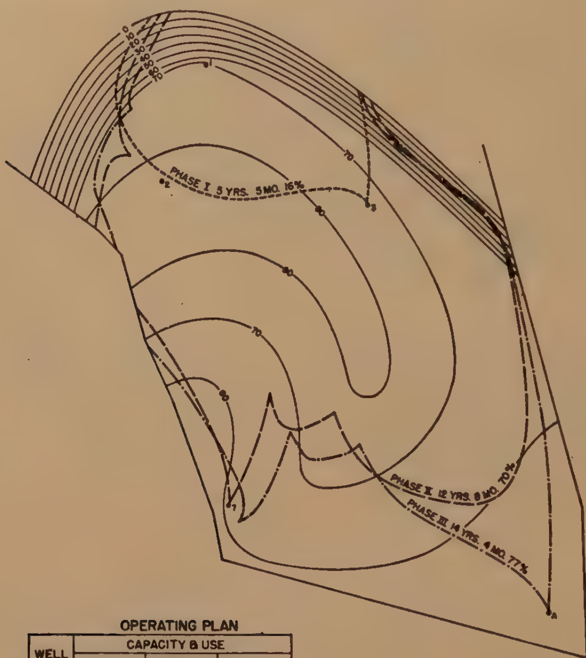
WELL	CAPACITY & USE		
	PHASE I	PHASE II	PHASE III
M	——	14.6 INJ.	16.7 INJ.
P	——	4.4 PROD.	5.6 PROD.
O	——	1.8 PROD.	——
9	——	4.8 PROD.	7.1 PROD.
N	——	3.6 PROD.	4.0 PROD.

NOTE: Capacities are in MMCFD.
Contours are isovols in M Bbls. per acre.

FIG 11—CASE B. PROBLEM NO. 3. SECTION 2.

reservoir to offset the limited producing ability of well "O."

When sufficient data had been obtained, an isovol map and revised rates were sent four years and one month after cycling was started. Model studies had been run on the assumption that the reservoir was not divided into more than one section,



OPERATING PLAN

WELL	CAPACITY & USE		
	PHASE I	PHASE II	PHASE III
1	10 INJ.	—	—
2	—	10 INJ.	15 INJ.
3	10 PROD.	15 INJ.	—
7	—	10 PROD.	—
A	—	15 PROD.	15 PROD.

NOTE: All capacities in MMCFD
Contours are isovols in M Bbls. per acre.

FIG 12—CASE C. PROBLEM NO. 1.

to the laboratory for another model study, the results of which, with some variation, approximated those of the original study of this reservoir. Dry gas broke into well 7 one year and ten months after cycling was started, which was only two months sooner than shown by the model study with 100 pct displacement. It was assumed from this agreement that the actual program was following the model study closely.

Two years and six months after cycling was started dry gas was evident at well 9, whereas the model study indicated that dry gas should not reach well 9 until and on this basis the presence of dry gas in well 9 could not be explained. No continuous shale barriers are present to cause separation. It was possible to divide the reservoir into two sections, based on the difference in permeability between the top and bottom of the reservoir. Isovol maps of the upper section or section 1 and the lower section or section 2 were prepared for model study. Cumulative volumes in and out of each section were estimated on a capacity basis. The results of the section 1 and section 2 model studies are shown in Fig 10 and 11. Assuming the division

of the reservoir into two sections, dry gas invaded well 9 through section 2. The dry-gas front (Fig 11, phase 3) is very close to well 9 in three years and five cycling, injection well "M" was deepened below salt water to inject also into the section now known as section 2.

Since the dry-gas front in section 1

OPERATING PLAN

WELL	CAPACITY & USE		
	PHASE I	PHASE II	PHASE III
1	10 PROD.	10 PROD.	10 PROD.
2	———	15 PROD.	———
3	15 PROD.	———	———
5	10 INJ.	10 INJ.	———
7	15 INJ.	15 INJ.	10 INJ.

NOTE: All capacities in MMCFD.
Contours are Isovols in M Bbls. per acre.

Fig 13—Case C. Problem No. 2.

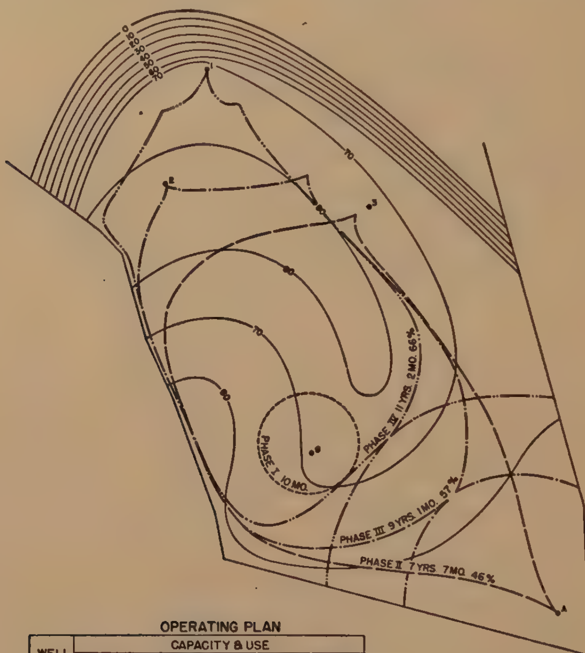
months. With a displacement factor of 80 pct, the time required for dry gas to reach well 9 would be two years and nine months, which time agrees with the observed dry-gas entrance into well 9.

Phases 2 and 3 in Fig 10 and Fig 11 represent the same time interval from the inception of cycling. Phase 1 is absent in Fig 11 because the original completion of injection well "M" was above water in section 1. Therefore, during the period represented by phase 1, Fig 10, all of the injected gas was going only into section 1. Eight months after the beginning of is considerably behind that of section 2 the following additional studies are planned: (1) conversion of well 7 from a producing to an injection well in section 1 only, in an attempt to make the dry-gas fronts from sections 1 and 2 more closely coincide when approaching the producing well "N"; (2) future producing rates, especially as to the possibility of shutting in well 9 and the injection well "M"; (3) after the dry-up of all present producing wells the advisability of completing a well on the western end of the ellipse, which well is now used as an injection well in a deeper

sand but which may be available. After cycling is complete, additional wet gas will be recovered by water drive without cycling.

ture which could have been afforded if a richer gas were yielded by the reservoir.

Because well 1 is in close proximity to the gas-water contact, it was desirable



OPERATING PLAN

WELL	CAPACITY & USE			
	PHASE I	PHASE II	PHASE III	PHASE IV
1	15 PROD.	7.6 PROD	15 PROD.	15 PROD.
2	———	———	10 PROD.	———
3	———	7.4 PROD.	———	———
6	15. INJ.	25 INJ.	———	———
A	———	10 PROD.	25 INJ.	15 INJ.

NOTE: All capacities in MMCFD.
Contours are isovols in M Bbls. per acre.

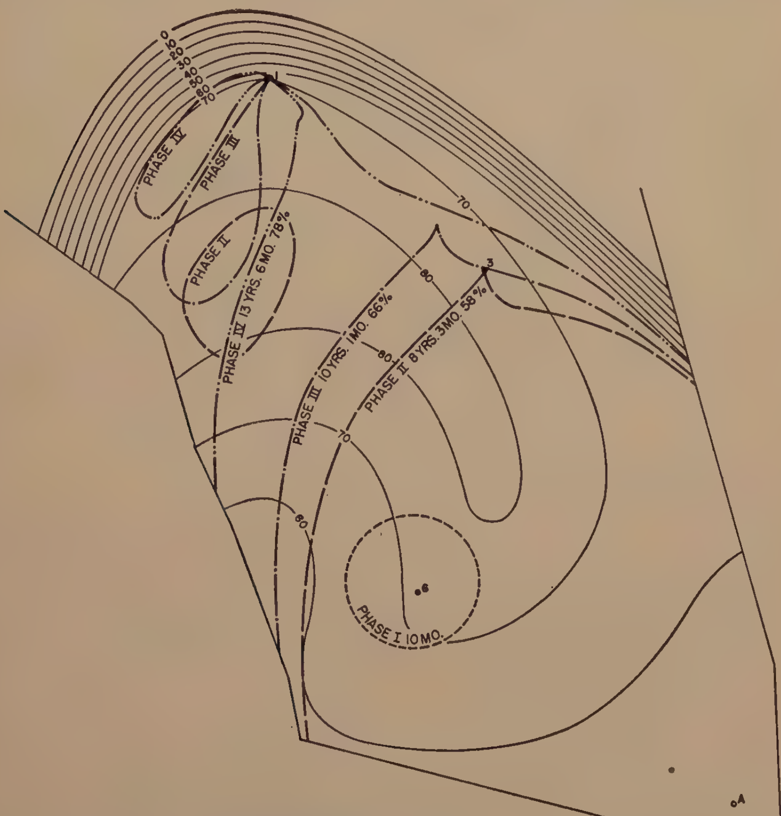
FIG 14—CASE C. PROBLEM NO. 3.

Case "C"

Case "C" is that of a reservoir which is bounded on the north by a gas-water contact and on the east, west, and south by faults as shown in Fig 12. Seven wells had been drilled within its limits in search of oil production, only one (well 1) being completed in this reservoir. The liquid content of the reservoir gas is low and will support a minimum of additional development for cycling. It was necessary, therefore, in designing a cycling program, to make all possible use of existing wells and to eliminate any unnecessary expendi- to inject into this well if possible. On the other hand, the capacity of well 1 was limited to 10 MMcfd because of mechanical conditions.

Problem No. 1 (Fig 12) uses injection into well 1 and production from well 3 until dry gas breaks through into well 3 as the first phase. The second phase consists of injection into well 2 and well 3 with production from well "A" (to be drilled) and well 7 and ends with the breakthrough of dry gas into well 7. The third phase continues with injection into well 2 and production from well "A" until breakthrough into well "A." The

rate of production and injection for the reservoir is 10 MMcfd for the first phase, 25 MMcfd for the second phase and 15 MMcfd for the third. At the conclusion life of the reservoir. The invasion by this program is fair; but it involves the use of a considerable number of wells, some of which might well be in use in



OPERATING PLAN

WELL	CAPACITY & USE			
	PHASE I	PHASE II	PHASE III	PHASE IV
1	15 PROD.	15 PROD.	15 PROD.	15 PROD.
3	———	10 PROD.	———	———
6	15 INJ.	———	———	———
A	———	25 INJ.	15 INJ.	15 INJ.

NOTE: All capacities in MMCFD.
Contours are isovols in M Bbls. per acre.

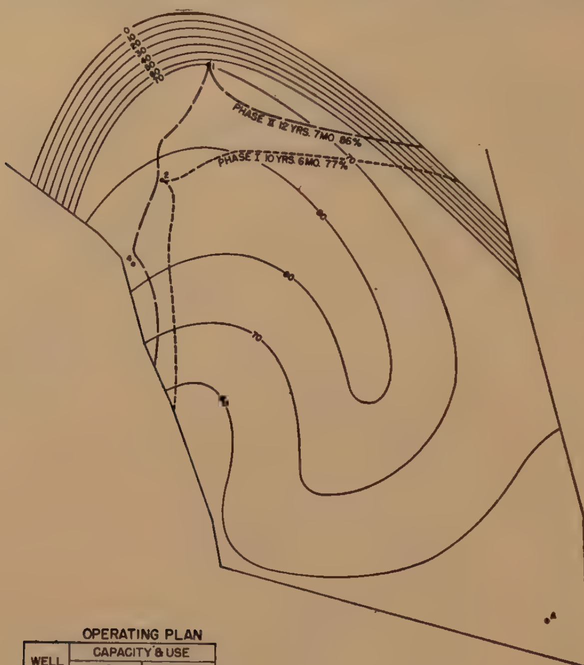
FIG 15—CASE C. PROBLEM NO. 4.

of this program 77 pct of the reservoir would be invaded by dry gas over a period of fourteen years and four months. The use of this program would require that one well be drilled, three wells be reworked, and gathering and injection lines be revised considerably during the another reservoir. Its disadvantages are its high cost and variable rate.

Problem No. 2 (Fig 13), as well as the remaining problems to be discussed involves production from well 1 and injection higher on the structure. In the first phase of problem number 2, gas is in-

jected into well 5 and well 7 and produced from well 1 and well 3 until breakthrough into well 3. The second phase consists of injecting into the same wells and producing from well 1 and well 2 until breakthrough into well 2. In the third phase gas is injected into well 7 alone and produced from well 1, the program being completed with breakthrough into well 1. The rate of production and injection for the first and second phase is 25 MMcfd and for the third phase the rate is 10 MMcfd. This program offers 55 pct invasion in nine years and eleven months, and its use would require that four wells be reworked with attendant costs for injection and gathering lines to serve them. This program offers a small invasion in view of the expenditures involved and is unsatisfactory because three of the five wells to be used are currently serving other purposes.

Problem No. 3 (Fig 14) follows problem number 2 closely in that injection in the first phase is into well 6 with production from well 1 for a period of ten months. Phase 2 follows immediately thereafter, and gas is injected into well 6 and produced from well 1, well 3 and from well "A" until simultaneous breakthrough into well "A" and well 3. In the third phase, gas is injected into well "A" and produced from well 1 and well 2 until breakthrough into well 2. The fourth phase consists of injection into well "A" and production from well 1 until breakthrough into well 1, at which time cycling is completed. The rate of production and injection for the first phase would be 15 MMcfd: for the second phase, 25 MMcfd: for the third



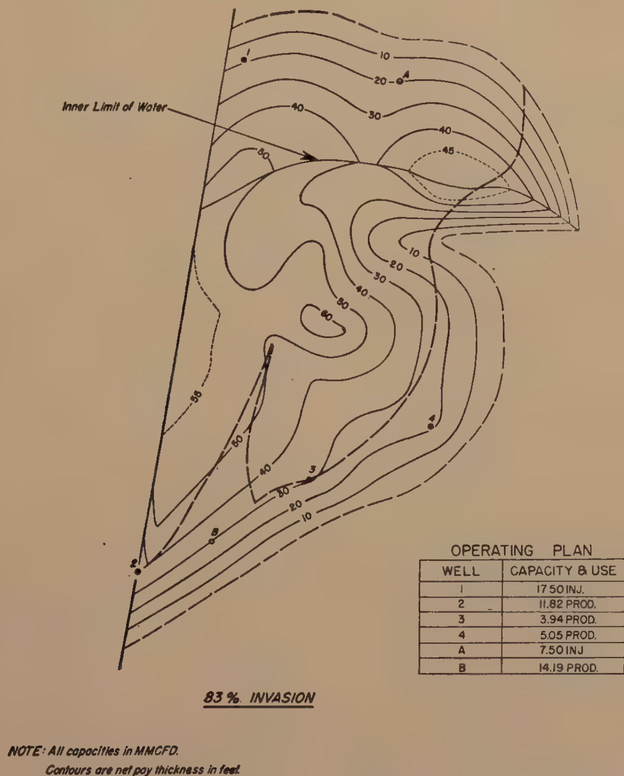
OPERATING PLAN

WELL	CAPACITY & USE	
	PHASE I	PHASE II
1	10 PROD	10 PROD.
2	15 PROD	———
4	———	1.54 PROD.
A	25 INJ	11.54 INJ

NOTE: All capacities in MMCFD.
Contours are isovols in M Bbls per acre.

FIG 16—CASE C. PROBLEM NO. 5.

phase, 25 MMcfd: and for the fourth phase, 15 MMcfd. The use of this program would invade 66 pct of the reservoir with dry gas in eleven years and two months, well 3. In the third phase, gas is injected into well "A" and produced from well 1 until the bubble of gas from injection into well 6 has drifted northward and



WELL	CAPACITY & USE
1	17.50 INJ.
2	11.82 PROD.
3	3.94 PROD.
4	5.05 PROD.
A	7.50 INJ
B	14.19 PROD.

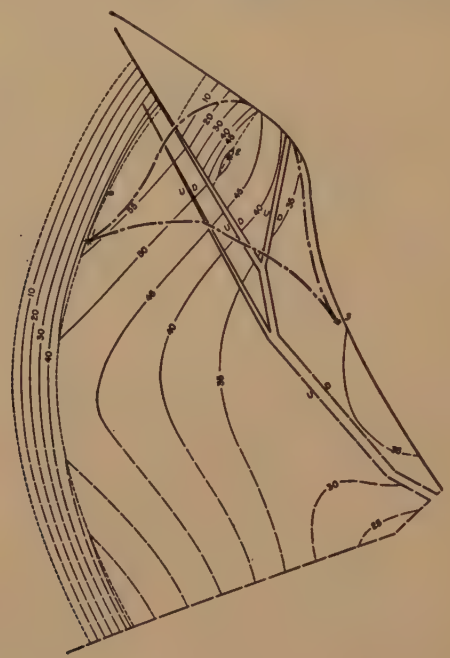
Fig 17—Case D.

and its use would require that one well be drilled and three wells be reworked with attendant cost for injection and gathering lines to serve them. The invasion afforded by this program may be considered fair but expenditures are comparatively high. In addition, one of the wells to be used is currently serving another purpose.

Problem No. 4 (Fig 15) consists of four phases. In the first phase gas is injected into well 6 and produced from well 1 for a period of ten months. In the second phase well "A" is used as an injection well and well 1 and well 3 are used as producing wells until breakthrough into broken through into well 1. In the fourth phase injection and production are the same but dry gas is produced from well 1 until breakthrough of additional dry gas from well "A." The rate of production for the first phase is 15 MMcfd: for the second phase, 25 MMcfd: and for the third and fourth phase 15 MMcfd. Through the use of this program 78 pct of the reservoir could be invaded by dry gas in thirteen years and six months. It would require that one well be drilled and two wells be reworked. The invasion offered by the use of this program is moderately high and at moderate cost. Its chief disadvantage is

that it requires the production of some dry gas from well 1 prior to breakthrough of the main dry-gas front from well "A." In addition, well 3 is currently serving other purposes.

Problem No. 5 (Fig 16) uses injection into well "A" and production from well 1 and well 2 in the first phase, which continues until breakthrough into well 2. For the second phase, gas is injected into well "A" and produced from well 1 and well 4 until breakthrough into well 1. The rate of production and injection is at 25 MMcfd for the first phase, and 11.54 MMcfd for the second phase. Under this program dry gas would invade 86 pct of the reservoir in twelve years and seven months. Its use would require that one well be drilled and two wells be reworked. This program offers the highest invasion with the lowest cost of any of the five programs herein discussed for case "C."



NOTE: Contours are net pay thickness in feet.

FIG 18—CASE E. ESTIMATED PATTERN.

Of the five problems run for case "C," problem number 5 obviously offers the best invasion pattern for this reservoir. Additional recovery by water drive may also be obtained in this case. This program offers a sustained rate of production for a long period of time and an even dry gas front, together with stable producing and injection conditions which should require small operating costs.

Case "D"

In the instance of case "D," as shown in Fig 17, the reservoir is bounded on the north by a gas-water contact, on the west by a fault, and on the south and

east by a pinch-out. Several wells had been drilled to this reservoir for production and many wells had penetrated it, having been completed in a deeper reservoir. The liquid content of the gas is high but low well capacities and small areal extent of the reservoir act to reduce earnings therefrom. At the outset, the operators owned two dual completions and four wells completed in this reservoir.

Fig 17 shows the cycling pattern which proved to yield the highest invasion compatible with the other considerations to be dealt with. Injection is into well 1 and well "A," with production from well 2, well 3, well 4 and well "B." This program invades 83 pct of the reservoir with dry gas and provides a sustained capacity of 35 MMcfd for the life of the operation. Well 2 and well 3 were owned at the outset, well 1 was a temporarily abandoned dry hole (too low to produce) cased through the reservoir, well 4 was a depleted oil well in another reservoir (purchased by the operators) and wells "A" and "B" were to be drilled.

Other studies made showed that:

1. The use of the two dual completions and the two wells used in the middle of the reservoir would result in lower invasion.

2. Greater invasion could be obtained by drilling well "A" for injection as close to well 1 as possible. However, for more complete knowledge of the reservoir the location was moved eastward to the point shown on Fig 17 at a small loss.

3. Some additional invasion could be gained by locating a producing well in the unswept area north of the reentrant in the eastern edge of the reservoir, but not enough to assure the return of the investment.

4. If sufficient capacity were available in the three other producing wells, and if some dry gas were processed, well "B" could probably be eliminated without appreciable loss in invasion, since the dry gas front will close the gap between wells 2 and 3 due to enlargement of the advancing dry-gas front.

In the light of the information gained from these preliminary model studies the operators concluded to start cycling with well 1 and well "A" for injection and wells 2, 3 and 4 for production. Cycling would be started in this manner and accurate tests of producing capacity would be made (which would then be possible) to determine if well "B" is necessary. Pending completion of revised and more

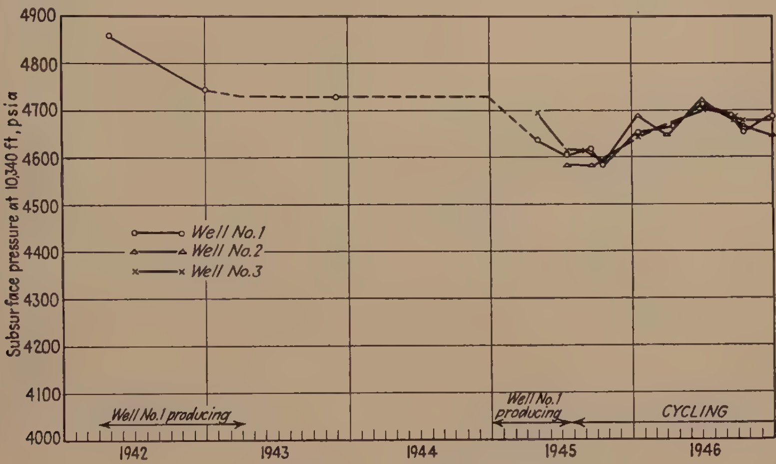


FIG 19—CASE E. PRODUCTION HISTORY.

complete model studies and the completion of well "B," if necessary, the two producers in the middle of the reservoir would be used to make up any deficiencies in producing capacity.

Case "E"

The last case to be cited herein is one in which the wells drilled prior to cycling furnished incomplete knowledge of the reservoir. Its complications are such that a model study was not even made; however, its cycling can, at this writing, be said to be successful.

Case "E," as shown in Fig 18, is bounded by a possible gas-water contact on the west and northwest, and by faults on the north-east, east and south. Minor faults are shown by correlation of electric logs to occur between wells 1, 2 and 3.

Well 1 was the first to be completed in this reservoir and began producing in March 1942. In May 1942, after a negligible amount of production, the reservoir pressure was found to be 4855 psia. Continued production resulted in a decline to 4742 psia in January, 1943, as shown in Fig 19. After intermittent production in the early months of 1943 and a five-month shut-in period during the latter part of the year, the reservoir pressure was found to be 4727 psia in December of that year. Well 1 remained shut in during 1944 and production was resumed in January 1945 on a continuous basis. In April 1945 the reservoir pressure was found to be 4636 psia.

The production history to this point had shown a continuous pressure decline with production and no indication of any increase in reservoir pressure was observed during a 17-month shut-in period. Volumetric balances failed to reveal a water drive but did show that the reserve was substantially as could be contained with the reservoir mapped as shown in Fig 18 if the minor faults shown between wells 1, 2 and 3 were ignored.

Wells 2 and 3, which had previously been completed in another reservoir, were reworked for cycling. After their recompletion in this reservoir, their pressures were found in July 1945 to be comparable with that of well 1, further indicating that there exists continuity across the minor faults separating these three wells.

Cycling was begun in July 1945 with injection into well 2 and production from well 1 and well 3. At this time, the invasion pattern, as shown in Fig 18, was estimated from experience with model studies for other reservoirs and the prediction was made that dry gas would enter well 1 in one year and into well 3 in one year and two months, barring interference by the minor faults separating the three wells and with a displacement factor of 65 pct.

During the course of cycling this reservoir, injection exceeded production and resulted in a general increase in subsurface pressure for all three wells. The variation in pressure between wells is probably no greater than the instrumental error in observing subsurface pressures.

Dry gas entered well 3 one month earlier than predicted by the pattern estimated at the beginning of cycling. At this writing, after some eighteen months of cycling, dry gas has not yet entered well 1. Variations in displacement factor or deflection of dry gas by the minor faults could be the reason for the delay in breakthrough into well 1. At this time, however, no firm conclusions have been drawn.

Conclusions

Model studies are of great benefit in the design and direction of a cycling operation. Each reservoir offers an individual problem and, as such, demands an individual solution.

The accuracy with which model studies can depict the course of cycling in any

reservoir is limited by: (1) the accuracy with which the configuration of a reservoir and its pay thickness, porosity, interstitial water, permeability, and fluid content of its component parts (if there be more than one) are known, and (2) the accuracy with which production from and injection into the reservoir, of any section thereof, is known.

In some instances where a model study has not been made or is not warranted, cycling can be cautiously undertaken by making all possible use of production data and the background of experience gained elsewhere. Under such conditions it is virtually impossible to predict invasion patterns or to integrate an entire cycling program, and recoveries may be expected to be lower than in a completely planned and controlled operation.

Acknowledgments

The writers are grateful to The Texas Company for permission to publish the material contained herein.

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DISCUSSION

W. Hurst*—Messrs. D. L. Marshall and L. R. Oliver have presented an interesting factual accounting of gas cycling in five different sands. Particularly interesting was the injection of gas below the water in zone A to complete the cycling pattern, a procedure never heretofore undertaken.

The title of this paper is quite appropriate, as the application of electrical models to gas cycling is a theoretical interpretation whose limitations must be recognized. In a model it is tacitly assumed that the sand is everywhere of uniform permeability, a condition that is accepted because it is impossible to reproduce the variations in permeability, even were such data available. Therefore what is determined by model studies is the most optimistic picture of gas cycling, because of the uniformity of the electrical medium, taking cognizance only of the geometric location of input with respect to the output wells and the limitations of the formation. Mr. A. F. van Everdingen and this reviewer in a recent paper[7] have proposed an analytical treatment of the relative by-passing of gas moving through permeable as compared to less permeable sand sections arranged in parallel sequence, employing the electrical model data. In the paper presented there is some reference to this subject, as it is discussed in the content that well 9 in case B actually showed invasion two years and six months after cycling was started, whereas the model data showed invasion four years after cycling. However, upon consideration of the sand as two different permeable sections the entrance of dry gas into well 9 agreed with the observed time for a displacement factor of 80 pct. It is hoped that with a continuation of this cycling study the authors will show to what extent permeability data can be applied to model studies to observe how this conforms with the actual cycling program, and by this factual comparison enhance our present knowledge of gas cycling.

* Shell Oil Co., Inc., Houston, Texas.

[7] W. Hurst and A. F. van Everdingen: Performance of Distillate Reservoirs in Gas Cycling. *Trans.* AIME (1946) **165**, 36.

Some Theoretical Aspects of Well Drainage and Economic Ultimate Recovery

By Vaughn Moyer*

(Los Angeles Meeting, October 1946)

Abstract

A method for incorporating well drawdown effect into reservoir calculations is presented in detail, together with examples of its use for widely divergent conditions that could be normally encountered in oil reservoir sands. Tentative conclusions as to the effect such factors as permeability, producing interval, well spacing, or well damage caused by completion or repair practice could have upon economic ultimate recovery are reached. It is carefully pointed out that the conclusions reached are subject to limitations indicated in the text, and placed upon all calculations made in the paper.

Introduction

Papers have been presented[1-3] in which theoretical depletion histories for reservoirs under equilibrium conditions and no appreciable well-bore drawdown pressure are determined. However, except for a limited number of cases, appreciable drawdown pressures in a well bore exist, and pressure and saturation gradients consequently vary throughout a reservoir.

This paper is an attempt to incorporate well-pressure drawdown into reservoir history, and to analyze certain factors, such as those involving recovery, well spacing, and productivity index, from the standpoint of permeability and drainage radius. By incorporation of drawdown into reservoir history, it is believed that theoretical considerations will more closely approximate actual reservoir behavior experienced in an oil field. For purposes of simplification, a solution gas-drive type field, without primary gas cap, has been selected.

Basic Data and Assumptions

Details of equilibrium saturation conditions for no drawdown production for various pressures in a reservoir are determinable by methods described by several authors[1-3] permitting the construction of a curve of oil saturation vs pressure for any selected combination of initial interstitial water and hydrocarbon saturation (Fig 1). This curve is then a description of equilibrium saturation conditions at any given pressure in a reservoir.

Developing the above, details of saturation and flow permeability may thus be determined for any increment or portion of a well drainage area or reservoir. In this manner the effect of pressure differential (drawdown) may be incorporated into reservoir and well drainage considerations.

It is pointed out that this method thus makes use of no-drawdown equilibrium production data, superimposing a drawdown effect upon them. It also assumes that net flow conditions in any considered increment of reservoir are not materially altered by the entrance of fluids from other increments into them, but approach equilibrium for the existing pressure and saturation (i.e., each increment behaves in more or less independent fashion, dependent largely upon the equilibrium considerations mentioned above).

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* Union Oil Company of California, Bakersfield, California.

[1] References are at the end of the paper.

It is recognized that this treatment of the flow problem (assuming a constant mass rate of flow across any considered increment), implies some rather large changes in gas-oil ratio with distance from a well, and probably creates some inaccuracy in the resultant findings. However, in the vicinity of a well bore, conditions approximate those assumed in the analysis, while in remote places (at or near the drainage radius) fluid movement in any particular portion of the sand is extremely small and consequently probably has little effect upon the overall picture as presented here.

A completely sound theoretical analysis would require the solution of simultaneous materials balance and fluid flow relationships for the history of the field. The basis for such a treatment by solution of simultaneous differential equations has been presented by Muskat et al.[6,7] The solution of such equations would be extremely complex, hence the simplification made here has been utilized. A detailed solution treating the problem as one of unsteady state flow throughout the life of the field would be necessary for absolute verification of the findings presented in this paper, but inaccuracies are believed to be small, and

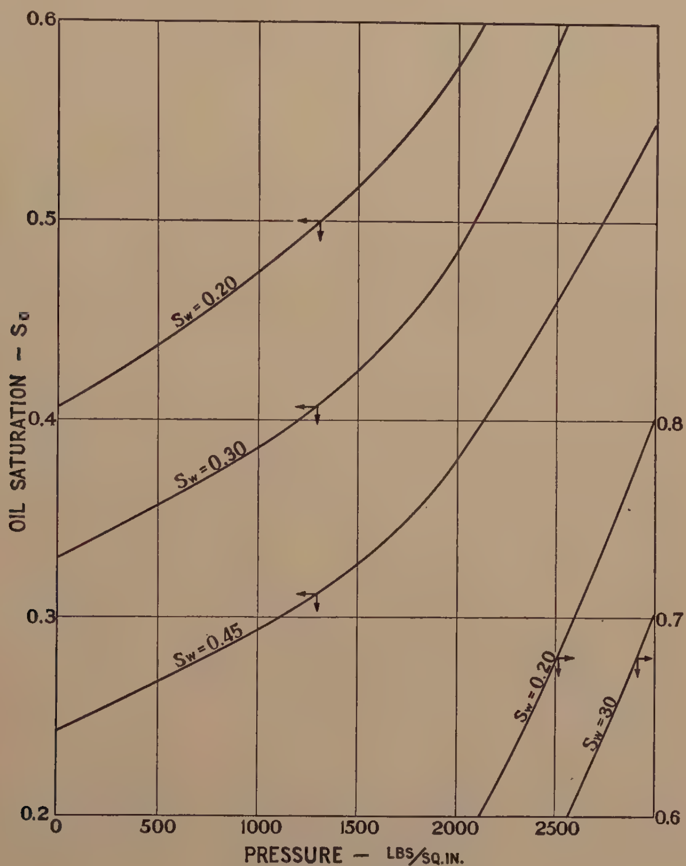

FIG 1—OIL SATURATION VS. PRESSURE.
(*After Babson, Tarner and Muskat.*)

such as to not materially alter the findings of this presentation.

For determining the curves of Fig 1 the basic data of Sage and Lacey[4] for Dominguez oil and gas were used for properties and water, were used as the best published information on this phase of the problem. Curves are presented for three values of interstitial water. Fig 1 was constructed on this basis.

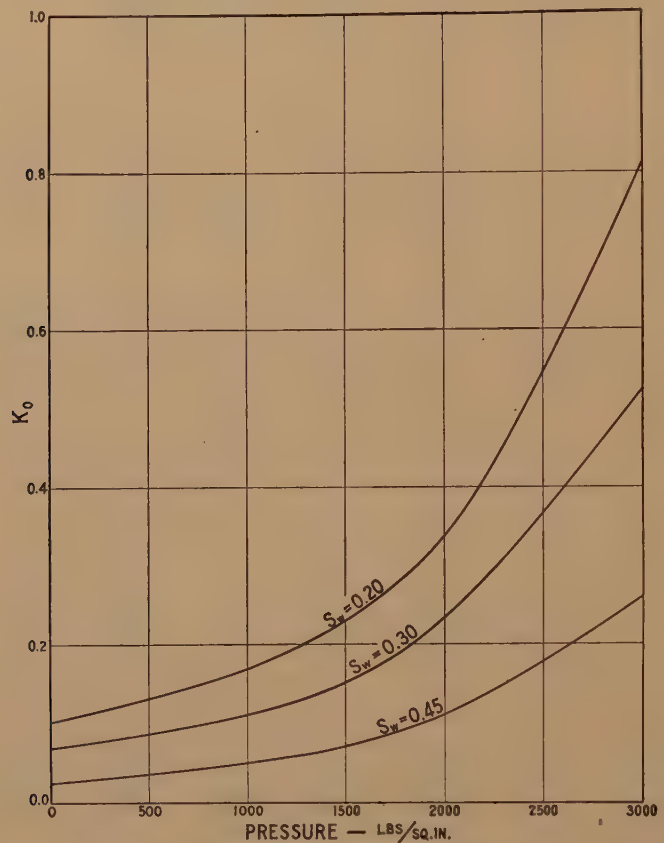

FIG 2—K_o VS. PRESSURE.
From Fig 1 and Leverett and Lewis data.

of the gas and oil, and a reservoir of 25 pct porosity was assumed. A reservoir material of 1.42 formation volume factor and saturated with gas (682 cu ft per bbl) at 3000 lb per sq in. and 220°F was used. The differential form of the materials balance equation outlined by Muskat[3] was used for determination of equilibrium oil saturation at various pressures, and the data of Leverett and Lewis[5] for the relation of relative permeability to saturation for gas, oil

Development of Method

Actual solution of the problem of determining pressure and saturation gradients around a well producing at a pressure appreciably different from that existing in a reservoir, as considered in this paper, involves dividing the surrounding area into concentric rings, and approximating the flow conditions across each ring under the limitations described above. If each ring is

considered as in a steady state condition, and the mass of oil flowing across it is taken to be a constant value, the relation between oil saturation, relative permeability and

$$P_e - P_w = \frac{\beta\mu_o \log_{10} r_e/r_w}{0.003073} \frac{Q}{K} \frac{1}{K_o} \quad [2]$$

or: $$P_e - P_w = \frac{Q}{K} \frac{\beta\mu_o}{K_o} \frac{\log_{10} r_e/r_w}{0.003073} \quad [3]$$

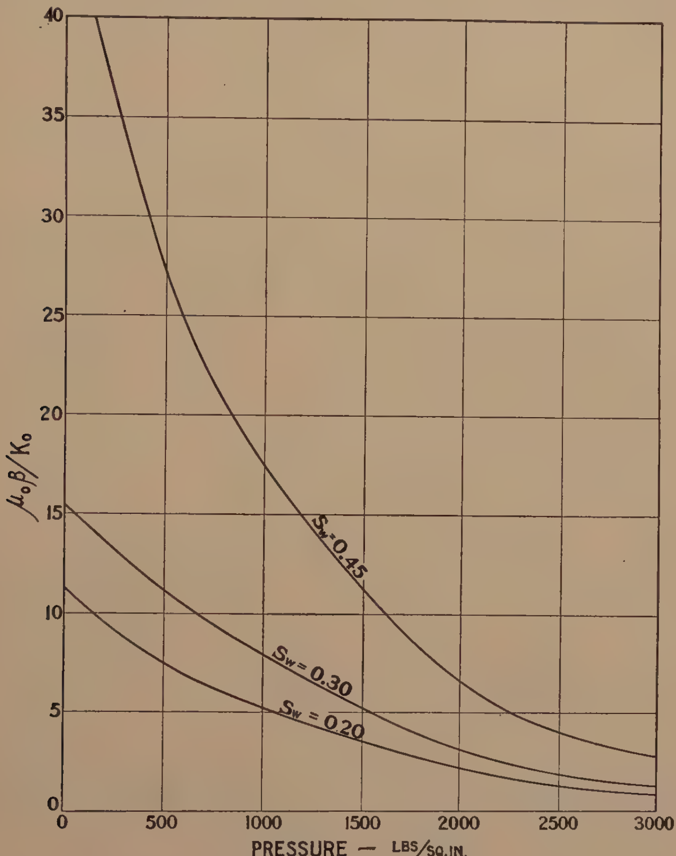

FIG 3—K_o VS. PRESSURE.
From PVT and viscosity data, and Figs 1 and 2. (For graphical solution of Eq 3.)

pressure for it can be outlined, and the pressure and saturation gradient calculated, although both vary continuously outward from the well bore. Discussion of the method and its development follow.

By substitution of proper constants, the basic formula for fluid flow may be written:

$$*Q = \frac{0.003073\, Kh(P_e - P_w)}{\beta\mu_o \log_{10} r_e/r_w} \quad [1]$$

then, for one foot of sand, this equation may be rewritten:

From Fig 1, which relates oil saturation to pressure, and the three-phase flow data of Leverett and Lewis,[5] a relationship of relative permeability (K_o) to pressure may be constructed (Fig 2). From PVT data,[4] the variation of oil-phase viscosity, μ_o and formation volume factor β, with pressure, may be determined. Then, by combining values of μ_o and β with values for K_o for various corresponding pressures, a curve of $\beta\mu_o/K_o$ vs pressure may be developed (Fig 3). If arbitrary values are assigned to Q/K in Eq 3 the equation may then be

* Nomenclature at end of paper.

rewritten as:

$$P_e - P_w = (\text{Constant})(\beta\mu_o/K_o)(\log_{10} r_e/r_w) \quad [4]$$

Furthermore, if concentric rings are selected such that the expression $\log_{10} r_e/r_w$ remains constant, the equation may be further simplified:

$$P_e - P_w = (\beta\mu_o/K_o)(\text{Constant}) \quad [5]$$

Then, by assuming any P_w (well-bore pressure), corresponding to an r_w (well-bore radius), a value for $\beta\mu_o/K_o$ can be selected for P_w. Substitution of this value in Eq 5 then leads to the determination of a P_e at a selected r_e. However, since $\beta\mu_o/K_o$ varies continuously with pressure, an average $\beta\mu_o/K_o$ (determined by trial and error method in this paper) corresponding to an average pressure for the interval must be used. Details of the method with a typical solution follow:

1. Assume $\beta\mu_o/K_o$ vs P relationship for $S_w = 0.30$ (Fig 3)

2. Assume Q/K to be 0.10. Note that Q/K is for one foot of sand, i.e.;

$$\frac{Q}{K} = \frac{Q(\text{Tank Oil})}{(\text{sand permeability-Md})\,(\text{Sand thickness-ft})}$$

3. For simplicity and ease of calculation, move out stepwise from well (assume $r_w = 0.3125$ ft) in doubling intervals i.e., 0.3125 ft to 0.625 ft to 1.25 ft, etc. This gives a constant value to $\log_{10} r_e/r_w = \log_{10} 2 = 0.30103$

4. Substitute the above in Eq 3, giving:

$$P_e - P_w = (\beta\mu_o/K_o)\frac{(0.10)(0.30103)}{0.003073} = 9.796\,\beta\mu_o/K_o$$

5. Now select a P_w for which a P_e is sought. In this case assume:

$$P_w = 1000 \text{ psi}$$
$$r_w = 0.3125 \text{ ft}$$

6. From plot of $\beta\mu_o/K_o$ vs P, locate $\beta\mu_o/K_o = 7.92$@$P = 1000$ psi (see Fig 3).

7. Substituting step 6 in relationship determined in step 4,

$$P_e - P_w = 9.796\,\beta\mu_o/K_o = (9.796)(7.92) = 77.6 \text{ psi}$$

Hence, $P_e = 1000 + 77.6$ lb $= 1077.6$ psi @ $r_e = 0.625$ ft

and

$$P_{\text{average}} = \frac{1000 + 1077.6}{2} = 1038.8 \text{ psi}$$

which would give $\beta\mu_o/K_o = 7.72$—which differs from original value selected in step 6 above.

Then reestimating $\beta\mu_o/K_o = 7.75$ (estimated average over interval involved)

$$P_e - P_w = (7.75)(9.796) = 75.8 \text{ psi}$$

and $P_{\text{average}} = \dfrac{1000 + 1075.8}{2} = 1037.9$ psi

giving: $\beta\mu_o/K_o = 7.74$

Estimated $\beta\mu_o/K_o$ of 7.75 is sufficiently accurated for solution.

8. For the next increment (from $r = 0.625$ ft to $r = 1.25$ ft), the new conditions then become: $P_w = 1075.8$ psi, $r_w = 0.625$ ft, $r_e = 1.25$ ft,

and a new solution is determined for these conditions as above.

A typical solution to a drainage radius of 640 ft is given in Table 1.

TABLE 1—*Solution to Drainage Radius*

r_w, Ft	r_e, Ft	P_w, Psi	P_e, Psi
0.3125	0.6250	1000	1076
0.625	1.25	1076	1148
1.25	2.5	1148	1216
2.5	5	1216	1280
5	10	1280	1342
10	20	1342	1400
20	40	1400	1455
40	80	1455	1507
80	160	1507	1557
160	320	1557	1605
320	640	1605	1650

By this method values of P_e (for any corresponding r_e) for any selected Q/K may be determined.

Economic Ultimate Recovery vs Sand Thickness and Permeability

For study of this problem, three hypothetical cases have been assumed; one for a sand of 10 md permeability and $S_w = 0.45$, another for a sand of 57 md permeability and $S_w = 0.30$, and a third for a sand of 500 md permeability and $S_w = 0.20$. These values were selected from an interstitial water vs permeability curve representative of a California oil field. Undoubtedly other combinations exist in other fields, but each field should be considered as a separate problem, and its own reservoir and fluid characteristics substituted in the necessary equations. An example of calculation method follows: Assume:* 10 ft of 10 md sand, depleted to a final rate of 5 B/D (rate at economic limit of production) of tank oil, that the well-bore pressure is 0 psi, and S_w is assumed to be 0.45.

then: $$\frac{Q}{K} = \frac{(5)}{(10)(10)} = 0.05$$

and: $$P_e - P_w = \mu\beta/K_o \frac{Q}{K}\frac{0.30103}{0.003073} = 4.898\ \mu\beta/K_o$$

*A drainage radius of 640 ft has been assumed for this and for all following examples.

Then, results will be as shown in Table 2. In similar fashion calculations can be made for widely varying conditions in a reservoir. Several cases are presented in Table 3, all for final rates of 5 bbl per day, and for a final producing well-bore pressure of 0 psi.

TABLE 2—*Calculations*

r_e, Ft	P_e, Psi	Increment, Ft	(1) Pore-Space-bbl Between Increments per Ft of Sand[a]	(2) Average Oil Saturation	(3) Average FVF	Residual Tank/Oil Bbl in Increment $\frac{(1)\times(2)}{(3)}$
0.3125	0					
0.625	200					
1.25	369					
2.5	510					
5	633	0– 5	3.5	0.271	1.117	0.85
10	744	5– 10	10.5	0.277	1.127	2.58
20	845	10– 20	42	0.282	1.136	10.43
40	940	20– 40	168	0.287	1.144	42.15
80	1,026	40– 80	672	0.293	1.152	170.92
160	1,106	80–160	2,688	0.297	1.159	688.81
320	1,183	160–320	10,752	0.302	1.165	2,787.21
640	1,254	320–640	43,008	0.306	1.172	11,229.10

Tank oil remaining in formation = 14,932.05 bbl per ft of sand.

$$\text{Initial tank oil in place} = \frac{(640)(640)(\pi)(0.25)(0.55)}{(5.61)(1.42)} = 22{,}210 \text{ bbl total.}$$

$$\text{Recovery} = \left(1 - \frac{14932}{22210}\right)(100) = 32.77 \text{ percentage of oil in place.}$$

Recovery = 22,210 − 14,932 = 7,278 bbl per ft sand.

[a] Net pore space available for hydrocarbons where the sand porosity is 25 pct.

TABLE 3—*Economic Ultimate Recovery vs Sand Thickness and Permeability*

Sand Thickness, Ft	Estimated Sand Permeability, Md	Interstitial Water Content	Tank Oil Recovery, Bbl per Ft Sand	Tank Oil Recovery, Percentage Tank Oil in Place	Final PI Drawdown Bbl per Day, Psi
10	10	0.45	7,278	32.77	0.00399
100	10	0.45	8,876	39.96	0.0223
10	57	0.30	10,408	36.82	0.0357
100	57	0.30	10,589	37.46	0.333
10	500	0.20	10,588	32.77	0.417
100	500	0.20	10,622	32.88	4.2

Table 3 indicates that for any given permeability economic ultimate recovery increases with sand thickness. This effect becomes small as permeability is increased, and is not of great importance in sands of over 100 md effective reservoir permeability. It is pointed out, however, that a very appreciable proportion of sandstone-

type reservoirs behave as if the effective reservoir permeability were less than 100 md, and the above relationship thus applies to a large number of reservoirs.

While actual barrels of tank oil recovered to economic depletion increases both with sand thickness and permeability, the percentage figure for recovery apparently varies in a more or less irregular manner. This irregularity arises in that permeability and interstitial water, hence tank oil in place, are related, but not in a simple or linear manner, thus creating such differences. Actually no anomaly exists although the percentage figures would so indicate.

No allowance has been made for gravity drainage, but since it also, in part, is dependent upon permeability, should not materially alter the above conclusions. It is probable that gravity drainage is of minor consideration in tight sands where the above is of greatest importance.

Effect of Water Blocking or Damage on Economic Ultimate Recovery

In many cases water invasion into a sand from a well-bore results in serious changes in permeability in the area immediately surrounding the well. The extent of damage consists in part, of the degree of swelling of clays, or other substances in the sand when it is invaded by drilling fluid or water. Such swelling tends to decrease permeability, and in line with published permeability-interstitial water relationships, hence to increase the interstitial water content or water retention capacity of the invaded sand. Undoubtedly other factors influence sands and damage them, but evaluation is difficult at best. For purposes of illustration of effects this paper has assumed that sand damaged is comprised of water invasion into the sand, swelling the clayey materials, or otherwise altering the sand such that its effective permeability is reduced to an arbitrarily selected lower value. This reduced permeability then requires a corresponding increase in interstitial water.

It should be mentioned here that the term interstitial water, as used in this paper, refers to water retained in the formation and not capable of being produced under the considered flow conditions.

As an example, and to study effects, a 10-ft sand section, having an initial permeability of 57 md and $S_w = 0.30$ has been selected. As a damage factor it is assumed that damage results in a reduction of effective permeability to 10 md, with a corresponding increase in the interstitial water content to 0.45 in the damaged section. Calculation of pressure profile and reservoir contents is carried out as demonstrated earlier in the paper, with the exception that two sand conditions are considered to exist, and consequently two equations for $P_e - P_w =$ (Constant) $(\mu_o\beta/K_o)$ must be used, one for the 57 md and one for the 10 md sand. A drainage radius of 640 ft has been used.

TABLE 4—*Well Damage and Economic Ultimate Recovery*

Depth of Damage into Sand, Ft	Tank Oil Recovery Total, Bbl per Ft	Loss by Damage, Bbl per Ft	Percentage Loss Ultimate Economic Recovery Through Water Block or Damage, Pct	Final PI
0	10,408	0	0	0.0357
1.25	10,012	396	3.80	0.01082
2.5	9,807	601	5.77	0.0086
5	9,644	764	7.34	0.0072
10	9,497	911	8.75	0.0063

From Table 4, the following observations may be made:

1. Large changes in productivity index are incurred for relatively minor water invasion and consequent damage to the sand. The significance of this change largely lies in the consideration of a time element. At lower PI values, the time for

accomplishing economic ultimate depletion becomes greatly extended.

2. Economic ultimate production loss

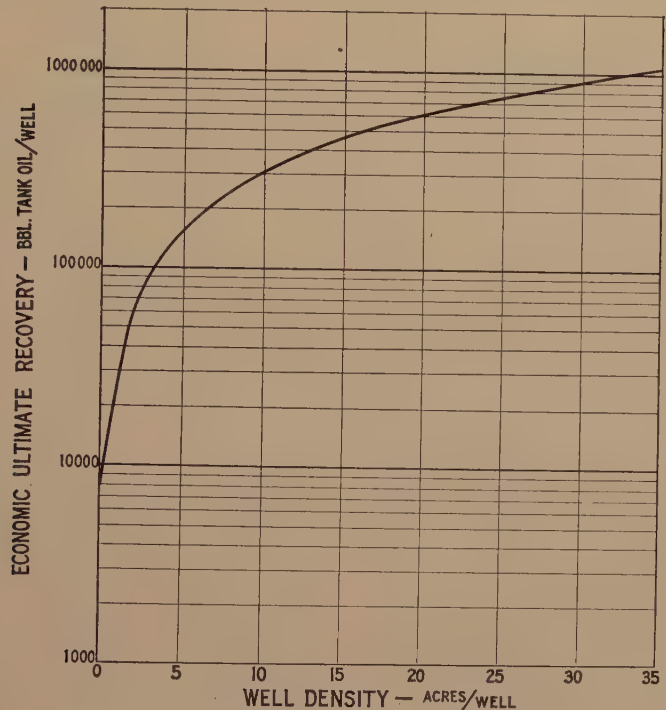

FIG 4—WELL SPACING VS. ECONOMIC ULTIMATE RECOVERY.

from well-bore damage is a significant quantity, especially in thin sands. Sand thickness is a modifying element, and generally tends to decrease effects outlined above as its value is increased.

Calculations made for other conditions, but not included here, indicate that the foregoing statements are of importance in sands of under 100 md effective reservoir permeability, but apparently have little or no significance for sands where effective reservoir permeability is greater than this value.

WELL SPACING AND ECONOMIC ULTIMATE RECOVERY

For purposes of illustration, recovery and spacing will be considered for a 100-ft sand, of 10 md effective reservoir permeability. A final rate of 5 *B/D* at abandonment is assumed.

TABLE 5—*Well Spacing and Economic Ultimate Recovery*

Drainage Radius, Ft	Acres Drained	Tank Oil Initially In Place, Bbl	Residual Tank Oil At Depletion, Bbl	Tank Oil Recovery, Bbl per Ft	Total Oil Recovery, Bbl	Tank Oil in Place Recovered, Pct
80	0.46	347	206	141	14,100	40.63
160	1.85	1,390	828	562	56,200	40.43
320	7.38	5,550	3,321	2,229	222,900	40.16
640	29.54	22,210	13,334	8,876	887,600	39.96

From Table 5, Fig 4 may be constructed. Then, assume that 30 acres are to be depleted on various well-spacing patterns, Table 6 will result from Fig 4;

Table 6 indicates that economic ultimate recovery, within the limitations of this

TABLE 6—*Well Density and Economic Ultimate Recovery*

Well Density, Acres per Well	Number Of Wells	Recovery, Bbl per Well	Total Recovery, Bbl
30	1	900,000	900,000
15	2	456,000	912,000
10	3	306,000	918,000
5	6	156,000	936,000

solution, apparently is not an important function of well spacing. Investigations have been made for other cases, and they do not differ materially from the one tabulated above.

Because of the implications of this conclusion, the necessary qualifications to make its statement possible are included:

1. A reasonably uniform sand body.
2. A simple structure, free of faults, etc.
3. No appreciable gravity drainage or water drive.
4. Production under the conditions assumed for flow in a reservoir as outlined earlier in this paper.
5. No impairment to permeability at or near a well-bore, such as might be experienced through accumulation of water, transported silt, deposited asphaltenes, or through completion or work over practice.

The principles of proper well spacing then become economic and mechanical in scope. An operator need but determine a most economic rate of operation, i.e., a balance between total production costs and profits on a time basis, and drill and space his wells accordingly. Of course, most fields are far from ideal structures, and sufficient wells to drain all parts of the structure must be drilled. Offset problems also complicate any spacing problem. It is stressed again that the above determination is based on equilibrium conditions, and is representative only under these circumstances. However, subject to the limitations of this paper, an operator apparently is faced with an economic problem, and may solve his requirements mainly on this basis.

Effect of Rate Upon Productivity Index

Also indicated by analysis is a relationship between productivity index and production rate. For an example a 10-ft sand of 57 md permeability and interstitial water content of 0.30 was selected. Results are shown in Fig 5. This curve shows productivity index to vary with rate for a given static pressure.

However, in determining the curve of Fig 5, equilibrium conditions were assumed at all times, hence the above conclusion applies only to equilibrium or long range conditions. The curve thus actually shows that a well will have a higher indicated potential after a long production period at a low rate than it would if operated at high rate for a comparable length of time.

This variation in potential with rate would probably not be noticeable in the ordinary field measurement of productivity index. Tests are usually conducted after short stabilization periods, during which equilibrium conditions are practically unaltered in the reservoir,[1] hence the productivity index usually shows but minor variation. Fig 5 is usable for equilibrium conditions only.

Summary

A method of studying reservoir behavior in which well-bore pressure drawdown effects are incorporated has been presented. Examples have been submitted indicating the use of this factor for the relating of sand thickness and permeability to economically producible reserves, determining the effect of well-bore permeability damage on economic ultimate recovery and productivity index, investigation of well-spacing in simple reservoirs, and for indicating the long-range variation of

productivity index with rate. Because of the scope of factors considered, this paper has done little more than touch on each problem, hence is qualitative in some of the assumptions made. It is hoped, however, that the general practicality and utility of the method outlined will be proved by field application.

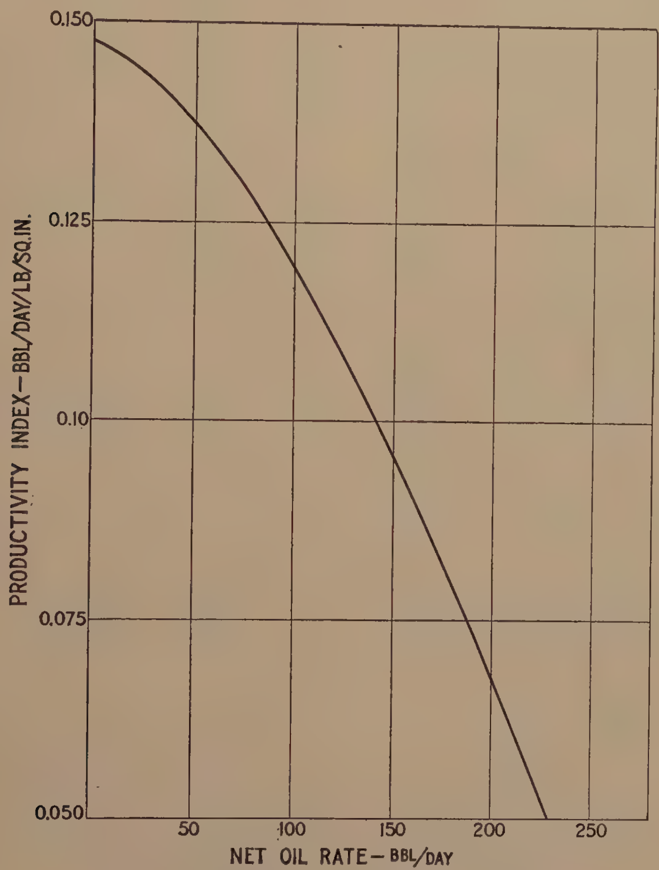

FIG 5—PRODUCTIVITY INDEX VS. NET OIL RATE.
For equilibrium conditions.

part. Each phase has been but briefly considered, and should be reviewed in greater detail before further conclusions are made.

It is recognized that the method outlined has definite limitations, both as to application and to interpretation. It is possible that further study may bring forth factors invalidating the above conclusions, or may show an improbability to exist in

ACKNOWLEDGMENT

The author wishes to acknowledge the helpful and constructive criticism of Mr. E. C. Babson and Mr. J. E. Sherborne, of the Union Oil Co., whose aid and suggestions were an invaluable contribution to the preparation of this paper. Grateful acknowledgement is made to the Union Oil Company for permission to prepare and present this paper.

Nomenclature

P = pressure, psig
Q = total volume—bbl per day of tank oil
K = permeability, millidarcies
h = sand thickness, ft
μ = viscosity—centipoises
r = radius—ft
K_o = relative permeability (oil phase)
S = saturation—fraction of total pores
PI = productivity index, bbl per day psi
β = formation volume factor—bbl per bbl
Subscripts:
e = refers to conditions at outer or drainage radius
w = refers to conditions at inner or well-bore radius
W = refers to water phase
o = refers to oil phase

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DISCUSSION

R. E. Loeck*—As Mr. Moyer has stated, the calculational methods of this paper depend upon the assumption of complete equilibrium and, further, that the oil saturation at any point in a reservoir is a function only of the reservoir pressure at that point. As a first approximation at least these assumptions appear reasonable. Without them, the calculations cannot be made. In conformance with these assumptions, the productivity index at any time is independent of the past production history and is dependent only on the pressure distribution from the well bore to the drainage radius. Thus, for any given drainage radius and drainage radius pressure (for example Fig 5), each rate of production from the well corresponds to a particular depletion of the drainage area. The higher the rate of production (the lower the equilibrium PI), the higher the depletion.

Uniform Areal Contribution to Production and Drainage Area

In this paper the pressure and saturation gradients around a well are determined by considering each concentric ring in a steady state condition, and the mass of oil across each ring is taken to be a constant value. In effect, this means that the oil flowing originates outside the drainage area and no oil is contributed to the flow from inside the drainage area.

In a similar paper, Messrs. Barlow and Berwald[8] assumed that each areal increment of sand contributes uniformly to the production from the well. At the drainage boundary the flow of oil to the well is zero. The rate of production intermediate between the drainage boundary and the well bore is proportional to the area of the annulus between any radius and the drainage boundary. Use of this assumption in the recovery calculations of the present paper will result in higher recoveries, due to the lower required rate of flow near the drainage boundary which, in turn, permits a lower pressure and hence a higher recovery.

In a field developed under uniform spacing, the drainage area of each well is a square, the sides of which are equal in length to the distance between wells, while the so-called "drainage radius" is equal to half the distance between wells. The flow converges from the outer boundary of this square toward the well; thus there is flow across the so-called "drainage radius." Since the area between the drainage boundary and the "drainage radius" is an appreciable part of the total drainage area, it should be included in well spacing-recovery calculations. As a practical expediency, this area may be incorporated into the area of the outer annulus in the calculations of this paper. The resultant percentage of recovery will be less than is calculated for a given drainage radius by the method outlined by Mr. Moyer.

The effect on recovery of considering uniform areal contribution to production is offset by

* Standard Oil Company of California, San Francisco, California.

[8] W.H. Barlow and W.B. Berwald: Optimum Oil-well Spacing. API Preprint 1946.

considering the entire drainage area. For example, using the data of the paper for 10 ft of 10 md sand, depleted to a final rate of 5 bbl per day, well bore pressure of 0 psi and S_w equal to 0.45; the calculated recovery is 32.73 pct compared to 32.77 pct in the paper. While the change in this case is admittedly quite small, the writer suggests that for completeness, these changes should be incorporated in the method of calculation.

Effect of Well-bore Radius on Recovery

The paper develops a method for determining the effect of well spacing on recovery. A study of the equation used for these calculations

$$Pe - P_w = \text{constant } x \frac{(Q)}{(Kh)} \frac{(\mu_o\beta)}{(K_o)}$$

indicates that it can also be used to calculate the effect of the size of the well bore on recovery for any particular drainage area. Using the data of the above example, the relationship shown in Table 7 is obtained.

Table 7—*Effect of Well-bore Radius on Recovery*

Well Radius, Ft	Well Diameter, In.	Recovery, Pct	Total Bbl Produced From 10 Ft of 10 Md Sand
0.15625	3.75	32.044	90,620
0.3125	7.50	32.73	92,550
0.625	15.00	33.26	94,060
1.25	30.00	33.99	96,120

These data demonstrate that ultimate economic recovery may be increased slightly by drilling a larger sized hole, or, in a tight sand, by shooting the well to increase the effective radius. Also, the productivity index is slightly increased, resulting in a shorter producing life. It is to be expected that the magnitude of this effect decreases with increasing permeability. Further, it is of interest to note that the magnitude of the change in recovery is the same as that shown in Table 5 for recovery versus well spacing. Thus the size of the well bore should also be considered in the economic analysis to determine the proper well spacing.

Effect of Water Saturation Gradient on Recovery

The calculations of the paper are based on the assumption of an immobile connate water. Actually, under a pressure gradient the water tends to flow toward the well bore and capillary pressure-saturation equilibrium demands that the water saturation become readjusted to conform to the pressure profile from the drainage radius to the well bore. The effect of this increase on water saturation toward the well is to decrease the productivity index and also the economic ultimate recovery, particularly in low permeability sands. The reduction in recovery may be expected to be similar to the example shown for water blocking. If the capillary pressure-saturation relations are known for the hydrocarbons, water and sand, the calculations of the paper can be modified to include this effect of the water saturation gradient.

V. Moyer (authors' reply)—It should be noted that the productivity index is not entirely independent of past production history, since it also varies with the general depletion of the reservoir. Actually, the productivity index is dependent upon both the state of depletion of the reservoir and the production rate or practice.

Commenting on the problem of considering flow across the drainage boundary, it is pointed out that practically all of the pressure drop occurs in the region immediately adjacent to the well, and in regions as remote as the drainage radius pressure changes for relatively large changes in radius become quite small. As Mr. Loeck points out, some lowering of calculated ultimate recovery probably is caused by this feature, but because of the small magnitude of the pressure change it is believed to be small, so that no important error is incorporated into the calculations and results presented in this paper.

D. S. Nutter*—This paper is of special interest among theoretical studies of reservoir behavior in that it attempts to take into account the drawdown of the individual well rather than assuming uniform equilibrium

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* Shell Oil Company, Incorporated, Long Beach, California.

conditions throughout the pool. This attempt is another step toward closer approximation to actual reservoir performance. It is, however, a difficult step which the author has found to necessitate some simplifying assumptions. In employing this method of attack and particularly in attempting to draw conclusions based upon it, we should keep well in mind these assumptions, which the author has been careful to emphasize. For example, the approximation may not be sufficiently accurate when it is assumed that net flow conditions in any considered increment of reservoir are not materially altered by the entrance of fluids from other increments, and that the mass of oil flowing across each ring is a constant value. It is particularly far-reaching to assign definite oil saturations to specific pressures as in Fig 1.

The indication (Table 3) that economic ultimate recovery is greater for thicker sands appears reasonable for perfectly uniform sands when it is realized that an economic limit of five barrels per day for 100 ft of sand is only 1/5 barrels per day per 10 ft of sand. However, it must not be concluded that for maximum recovery a well should be completed with as much zone as possible open; in the actual case the sands nearly always are far from uniform, and the completion from too great an interval may easily lead to subsequent difficulties and decrease in ultimate recovery.

In many cases the loss of recovery from a well damaged by water block appears greatly to exceed the losses suggested by Table 4. In general a substantial decrease of the productivity index of a well does not mean that the time for accomplishing economic depletion becomes greatly extended, but rather that the recovery during the normal life of the well is substantially decreased, as the well is part of a group and its economic life is not independent of the rest of the group.

The tentative conclusion of this paper with regard to well spacing—i.e., that the effect of spacing on ultimate recovery is practically negligible—is dependent upon the underlying assumption that oil saturation and hence recovery is determined by the pressure. If this is true, then to produce efficiently a simple, uniform, depletion-type reservoir it is necessary only to reduce the pressure and collect the fluid produced. If, on the other hand, oil recovery is dependent upon the development program or the production procedure as well as upon the initial and final reservoir pressures, then the saturation-pressure relationship is not fixed, and conclusions derived therefrom regarding the effect of well spacing upon recovery should not be expected to hold.

V. Moyer—By and large, two forces act to bring oil from a reservoir to a well. These are the development, by any means, of a pressure difference between the bore hole and some point in the reservoir, and the movement of fluids into the well by gravitational forces, which again rely on the development of a pressure differential. Spacing, then, becomes a problem of determining the distance over which a pressure difference is to be created, or that of determining what final pressure in a reservoir will yield the greatest economic ultimate recovery. Where large pressure differences are necessary to maintain production at economic levels, closer spacing is imputed to reduce the abandonment pressure in the reservoir, and from Fig 1 of this paper, to lower the final oil saturation, hence increasing the ultimate economic recovery. As suggested by the calculations in the paper, such closer spacing, at least in tighter sands, apparently cannot be justified economically, for the purpose of increasing the ultimate economic recovery from such a reservoir, subject to the limitations pointed out in the paper.

E. V. Watts*—This paper helps to further the conception of reservoir behavior which we derive from laboratory data.

The work of Leverett and Lewis on well-sorted, 5000+ md sand is highly regarded by the industry. However, one can hardly refrain from remarking that an important milestone will be passed when it is no longer necessary to refer to their data as "the best published information" when predicting the performance of California sands having an effective permeability of 10 md. The recoveries calculated by Mr. Moyer are considerably higher than we ordinarily experience in the field. This may be due in part to the differences

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* General Petroleum Corporation, Los Angeles, California.

in the behavior of sand encountered in depletion-type fields and that studied by Leverett and Lewis.

In Mr. Moyer's sample calculation of radial pressure and liquid saturation it will be noted that roughly 90 pct of the pressure drop occurs in 10 pct of the sand nearest the well. For the purpose of calculating pressure losses then, it seems entirely rational to assume that the oil rate across each concentric boundary is constant. In effect, the calculations provide a method for calculating the abandonment pressure in the remaining 90 pct of the sand. Whether or not the saturation in this large fraction of the reservoir can be related solely to the pressure would require further analysis of unsteady-state flow. Any improvement in Mr. Moyer's calculations would be exceedingly complex and might best be handled by electrical computing devices.

Just as the oil rate across concentric rings may be assumed constant, so may the gas rate be assumed constant. However the latter condition cannot be fulfilled by using Fig 1 inasmuch as the methods used in calculating it associate a unique, rapidly changing gas-oil ratio with each value of pressure. Properly speaking, a family of curves for varying ratios would have to be drawn for each value of water saturation. But since small changes in saturation result in large changes in ratio, it may be that the condition of constant gas rate can be satisfied without materially altering Mr. Moyer's results.

In conclusion, it may be unnecessary to emphasize that Mr. Moyer's calculations of damage by water-blocking represent a sort of intrinsic loss, or that which results at various abandonment pressures without considering the influence of other wells. For an actual reservoir in which a damaged well is surrounded by relatively undamaged wells, the recoveries become more nearly proportional to the productivity indexes, with the damaged well suffering a reduction in drainage radius. This effect would be more likely to prevail in sands of high permeability where the calculated intrinsic loss is least.

Apparatus for Determination of Volumetric Behavior of Fluids

By B. H. Sage,* Member AIME and W. N. Lacey*

(Los Angeles Meeting, October 1947)

Abstract

Apparatus and a method for determining the volumetric behavior of hydrocarbons at pressures up to 10,000 psi[a] and at temperatures between 0° and 460°F are described. The equipment is suitable for measuring the total volume of the system and the volume of a liquid phase as functions of state within these ranges of temperature and pressure.

Introduction

During the past two decades there has been a marked increase in the ranges of temperature and pressure encountered in underground hydrocarbon reservoirs of commercial interest. In addition, greater interest in the intensive characteristics of the fluids found in these reservoirs has developed.

Apparatus

Several types of apparatus have been developed in the authors' laboratory for volumetric measurements of hydrocarbon systems. The earliest equipment described[1] was characterized by constant volume, and the weight of material present was varied systematically in order to attain the different pressures desired in the study. Later another apparatus[2] was built in which the effective volume of the cylindrical cell, which confined a hydrocarbon sample of constant weight was varied by injection or withdrawal of mercury. The effective total volume of the equilibrium cell was measured by ascertaining the position of the mercury surface but no measurement could be made which gave knowledge of the volumes of individual phases existing within the hydrocarbon system.

A third apparatus[3] was designed for use at higher pressures and temperatures than the earlier equipment would tolerate. This apparatus was of the variable volume type but was built in the general form of a U-tube, the mercury level being measured at the surface which was not exposed to the hydrocarbon system. This arrangement avoided the need of subjecting measuring equipment to the extremes of temperature at which studies were made, but it gave no provision for measurement of the volumes of individual phases. Although this last apparatus was satisfactory as to accuracy and convenience for many purposes, need was felt for measurements of the volume of the liquid phase of the hydrocarbon system.

For this reason a fourth equilibrium apparatus was designed and constructed, and it is the purpose of the present paper to describe it. The equilibrium cell has a working range of temperature from 0° to 460°F at pressures up to 10,000 psi. Provision for measurement of both total volume and liquid-phase volume makes it particularly suitable for the equilibrium study of heterogeneous systems consisting either of simple mixtures or of complex field samples of hydrocarbons.

The general arrangement of the ap-

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[a] All pressures cited are absolute.

[1] References are at the end of the paper.

paratus is shown in Fig 1. The equilibrium cell A is immersed in an agitated oil bath, the temperature of which is controlled by equipment similar to that extends from it through the rod are insulated from the rod and the cell. Thus by connecting the metal of the cell to the other side of an indicating circuit, a signal

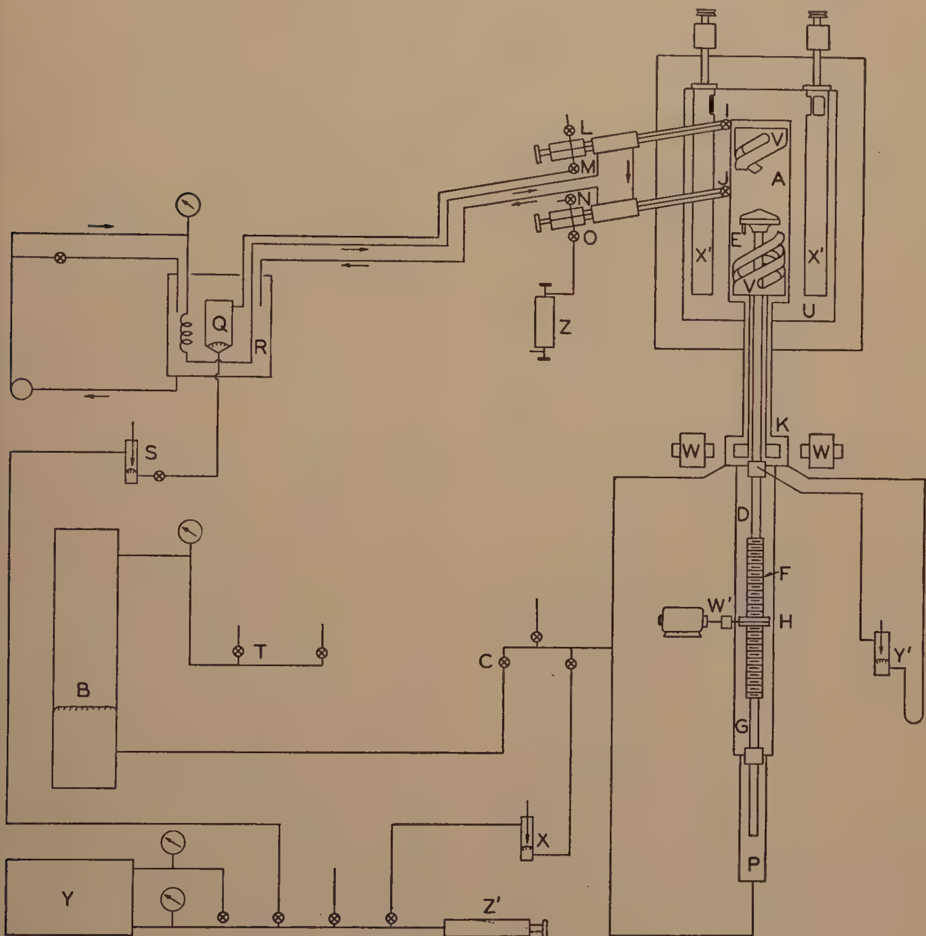

FIG 1—GENERAL ARRANGEMENT OF APPARATUS.

described elsewhere.[3] Mercury can be added to the cell from the reservoir B through the valve C, or withdrawn through the same connections. A vertical rod D entering through the lower part of the cell carries at its upper end a mercury-level indicator E consisting of an electric contact point extending downward. The point and the electric lead wire which is given when the point is lowered until it makes contact with the mercury surface. The rod D leaves the mercury-filled part of the cell through a gland in the lower wall of the chamber K. This gland allows vertical movement of the rod without permitting more than very slight leakage of mercury from the equilibrium cell. The rod below the gland is connected to

an accurately machined lead screw F which is driven by an electric motor through a worm engaging a gear attached to the nut on the lead screw. These parts are sufficiently carefully constructed so that a revolution counter W′ on the worm shaft H, after suitable calibration, gives the location of the contact point E with an uncertainty of less than 0.002 in.

In order to avoid changes in the total volume of the cell system as the rod D is raised or lowered, a rod G of the same diameter as the rod D is attached to the lower end of the lead screw and passes through a gland into the chamber P which is filled with mercury and is connected to the equilibrium cell. Not only does this compensating device eliminate any effect of movement of the rod on the total volume of the fluid-filled system but it also serves to avoid appreciable movement of the level indicator point E as a result of change in pressure within the cell since on increase of pressure the only significant deformations are those of elastic compression in the screw F and of elastic extension in the housing surrounding it.

Two valves are built into the equilibrium cell wall, valve I at the top of the cell and valve J at approximately half the maximum working volume. The former connects to a vacuum pump through valve L or to apparatus for adding or withdrawing samples through valve M. Samples may likewise be added or withdrawn through valve J by way of valve N or O. Valve N permits evacuation of the lower manifold independently of the equilibrium cell.

Attainment of equilibrium within the cell is hastened by means of a spiral agitator V, which is designed so that the free cross section within the cell is the same at each elevation, except near the top and bottom of the cell, where measurements of mercury-hydrocarbon or hydrocarbon liquid-gas interfaces are avoided. This spiral agitator is driven by means of a tubular shaft to which is attached a soft iron armature within the case K. The case is constructed of stainless steel of relatively low permeability. Close outside the case is a revolving electromagnet W of sufficient flux to induce the necessary torque in the shaft to drive the spiral agitator at a speed of approximately 100 rpm, despite the presence of the case K which must withstand the maximum working pressure of the equilibrium cell.

Experimental Procedure

The general experimental procedure for determining the pressure-volume-temperature relations of hydrocarbons begins by transferring a known weight of a hydrocarbon mixture to the equilibrium cell A after careful evacuation of the cell through valve I by means of a mercury diffusion pump. Gaseous hydrocarbons are added quantitatively from reservoir Q through valve M. The pressure vessel Q is surrounded by an agitated oil bath R which has automatic temperature control. Fluid connection from the mercury which acts as confining liquid in reservoir Q to the pressure-measuring equipment is made through the mercury-oil interface in the trap S. The quantity of noncondensable gas added to the equilibrium cell A is determined from the corresponding isothermal decrease in pressure within the reservoir Q, which is calibrated for each gas used.

Samples of volatile liquid components are added by distillation from a weighable vessel, while complex or relatively nonvolatile liquids are displaced into A from a suitable container Z through valve O. After completion of the addition of the sample, the equilibrium cell is brought to the desired temperature by means of the oil bath U whose temperature is controlled by suitable electronic equipment to be described later, stirring being accomplished by two circulating agitators, X′.

Attainment of phase equilibrium within the cell A is hastened by use of the spiral agitator V. The equilibrium pressure within the cell is determined by means of the fluid pressure balance Y which is connected to the cell by an oil-filled tubing line through the mercury-oil interface in the trap X. The position of the mercury-hydrocarbon interface within the equilibrium cell A is determined by means of the electric contact point E, the reading being taken from the revolution counter W′ on the worm shaft. Such readings can be interpreted in terms of volume of the hydrocarbon sample through calibrations previously made.

Since in heterogeneous systems it is desirable to measure not only the total volume but also the volumes of each of the phases present, a second type of level indicator is provided at the upper end of the rod D. It consists of a short length of very fine wire through which a small current is passed in order to raise its temperature slightly above that of its surroundings. The wire is also one arm of a resistance bridge in which the circuit is kept balanced. If the rod is raised so that the indicator is in the gas phase with the bridge balanced, and then it is lowered slowly by operation of the motor and worm H, the bridge circuit will remain substantially in balance until the fine wire makes contact with the gas-liquid interface. At this time the rate of energy dissipation from the wire will suddenly change and this will in turn affect its temperature and thus its resistance, throwing the bridge circuit out of balance. At this position of the rod the reading of the counter W′ is ascertained and from the calibration the volume occupied by the gas phase is determined. The volume of the coexisting liquid phase may then be found by difference between the volumes of the gas phase and the system as a whole.

After a sample has been prepared in the cell A its total volume may be changed, together with the pressure, by admitting or withdrawing mercury through valve C, the air pressure in reservoir B being suitably adjusted by means of valve T and the relief valve adjacent to it. After attainment of thermal and phase equilibrium at one state of the system the corresponding pressure and volume readings are taken. Holding the system at constant temperature, measurements are made at a series of total volumes so chosen that the pressure is varied throughout the working range. Some measurements are made after an increase of volume while others follow a decrease, a procedure which serves to test the attainment of equilibrium. When the measurements at one temperature are complete, the temperature of the system is changed and the process is repeated.

Details of Construction. The details of construction of the level indicator are shown in Fig 2. The head is divided into two parts, the cap A′ and the nut B′, which are separated by mica insulation. The lead wires from the hollow rod D are sealed by the soapstone sleeve C′ which is held in compression by the nut B′. The electrical leads connect two insulated pins in the nut, one of which is approximately 0.030 in. longer than the other. The elevation of the mercury surface is determined by means of an electric contact at the end of the longer pin E′. Between the shorter insulated pin F′ and a grounded pin of the same length (not shown) is welded a length of approximately 1 in. of platinum wire 0.0037 in. in diameter. This wire is attached to the pins by a spark-welding technique. Effort is made to have the wire normal to the axis of the hollow rod D with an uncertainty of not more than 0.0005 in. The cap A′ is of such shape that small drops of liquid phase or mercury will not accumulate on it. Special precautions were taken to insure that all interstices of the head were filled with mica or soapstone

in order to avoid the gradual accumulation of mercury or hydrocarbon materials within the head, with the attending contamination of subsequent samples. It was found that the design shown in Fig 2 was such that the head could be immersed in mercury for an extended period at elevated pressures without the penetration of enough mercury to change appreciably the resistance between the contact circuits and ground.

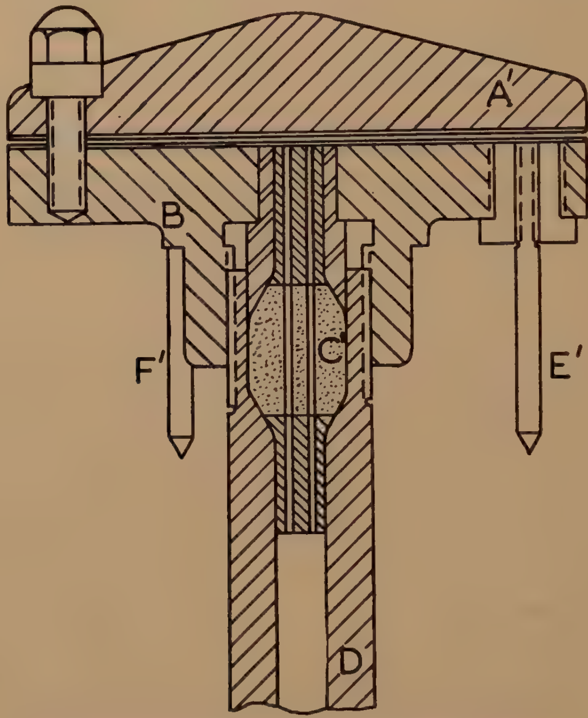

FIG 2—DETAILS OF CONSTRUCTION OF LEVEL INDICATOR.

The design of the equilibrium cell A of Fig 1, and its agitator is shown in Fig 3. The body of the cell was prepared from stainless steel (18 pct chromium and 8 pct nickel) which had been fully annealed. The billet was rough-machined and then annealed before the final machining was accomplished, in order to prevent changes in dimensions of the cell with time. Every effort was made to keep the cross section of the cell the same at various heights within 0.03 pct. The upper part of the cell was closed with an unsupported-area seal of a design slightly different from that described earlier.[3] It was desired in this case to avoid large changes in the volume of the system above the mercury surface and therefore the sliding block D′ of Fig 3 rests upon a small land and is sealed to the wall of the cell by a ring under compression from the follower F′ which is held in place by screws threaded to the block G′. This block in turn engages threads in the cell A. This arrangement of the upper closure of the equilibrium cell avoids changes in calibration equivalent to more than 0.001 in. of movement of the sliding block D′.

The valves used for the addition of samples to the system and for its evacuation are given a small upward slope so as

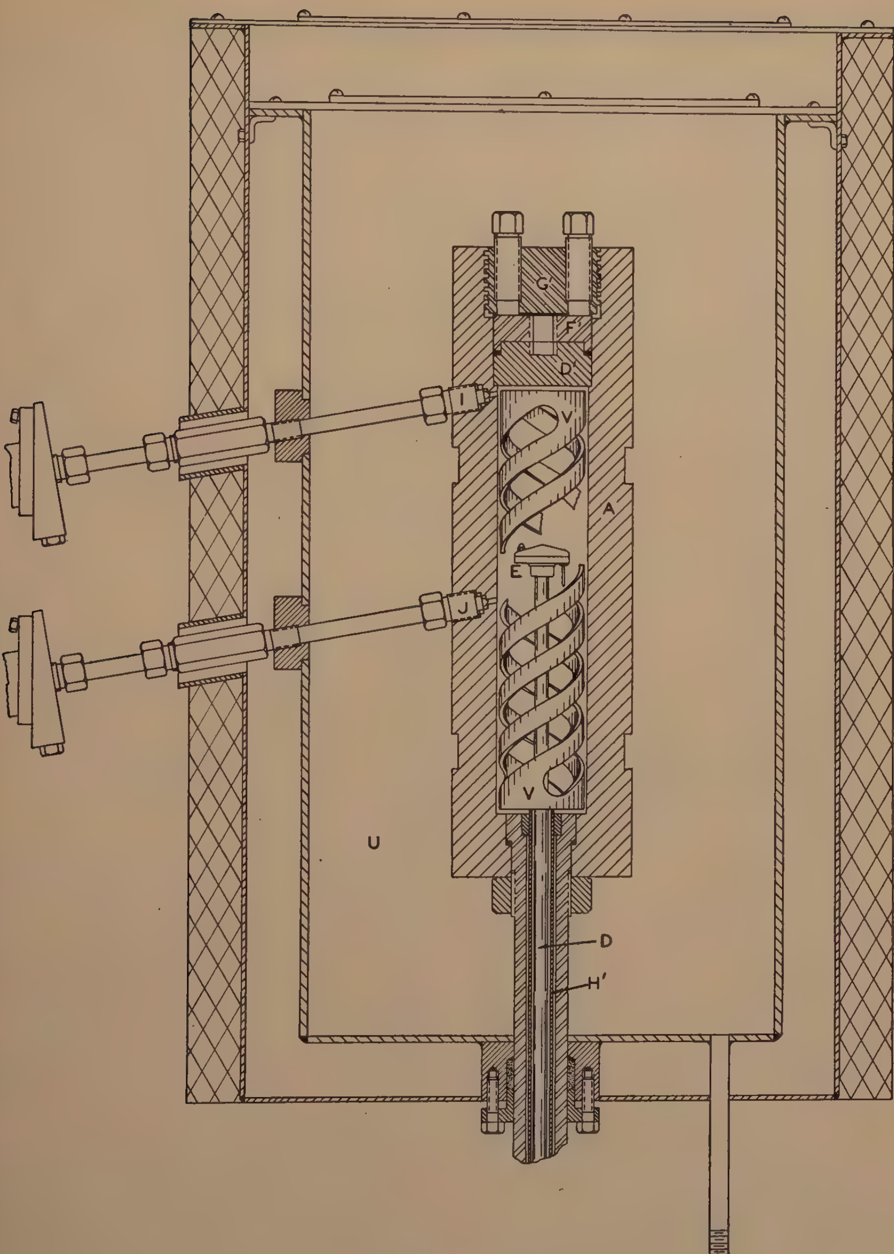

FIG 3—EQUILIBRIUM CELL.

to avoid the trapping of gaseous material during addition of samples. The valve stem and seat at I and J are so arranged that the threaded stems are external containing 18 pct chromium and 8 pct nickel. A triple thread helix was cut through the walls of the tube with a lead of approximately 4½ in. This work was carried out

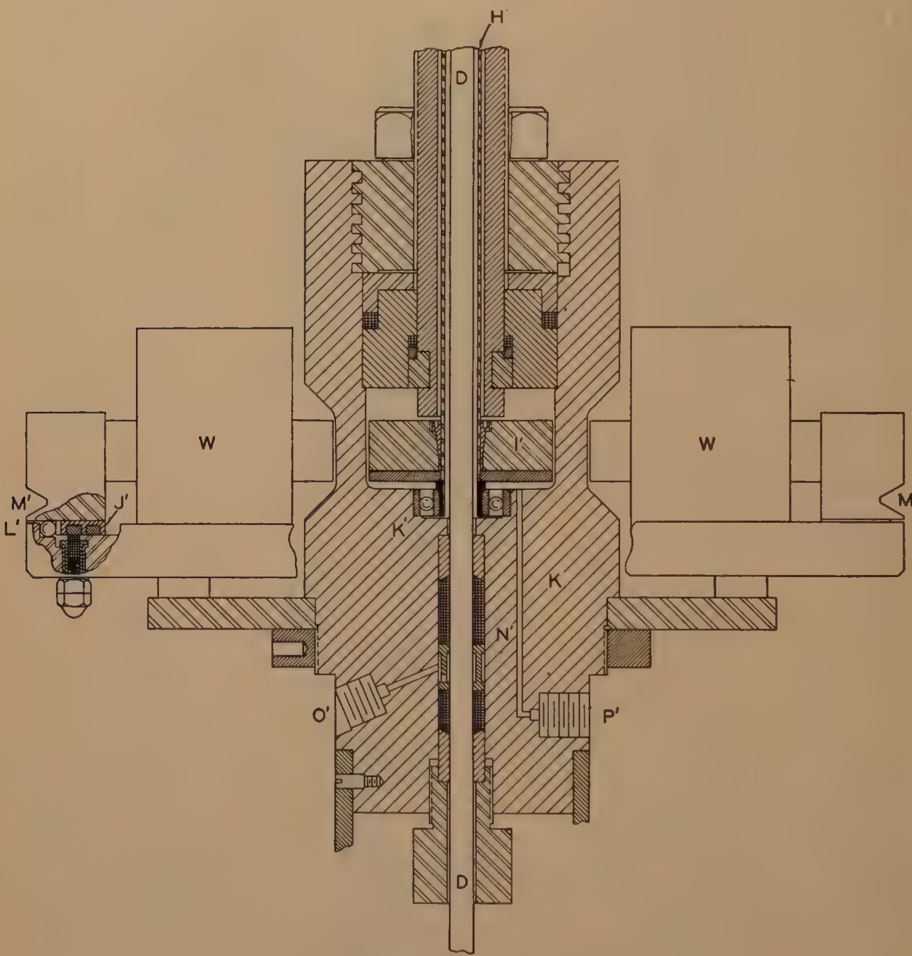

FIG 4—MAGNETIC AGITATOR DRIVE.

to the packing glands and lubrication of the threads does not contaminate the sample. The valve stems have monel metal tips which seat against a suitable part of the equilibrium cell A. The packing gland and rotating parts of the valve stem are outside the oil bath U.

The spiral agitator V was machined from a fully annealed stainless steel tube with care, utilizing spiral milling equipment. The variation in the cross section of the agitator in different parts of the working section of the equilibrium cell is much less than the corresponding variation in cross section of the cell itself. This spiral agitator induces sufficient circulation parallel to the axis of rotation to decrease markedly the time required

for the attainment of either homogeneous or heterogeneous equilibrium as compared to equipment described earlier.[2]

The spiral agitator is driven by means of the tube H′ of Fig 3 and 4 which is concentric with the level indicator rod D. This tube carries at its lower end the soft iron armature I′ of Fig 4 confined within an annealed stainless-steel case K around which are rotated the electromagnets W. These electromagnets are energized through a suitable collector ring system shown at J′. Adequate torque is transmitted through the stainless steel case with the flux density used and the agitator drive operates satisfactorily while immersed in mercury.

Two unsupported-area seal rings shown at K′ are used to prevent leakage of mercury from around the armature I′. The tube H′ is supported by the ball bearing K′. The electromagnets W are rotated on the ball race L′ by a V-belt drive operating on the grooved pulley M′.

The rod D passes through the block K and is sealed by means of the packing gland N′. This gland is provided with a lantern connected to a source of oil through the fitting O′. This oil is maintained at a pressure approximately 5 psi higher than that within the agitator chamber. This is accomplished by suitable interconnection with the mercury-filled portion of the system through the connection P′, as shown in Fig 1. The oil in the lantern serves to lubricate the rod D and to eliminate leakage of mercury completely. The gland is often used for more than a year without need for adjustment and there is no evidence of contamination of the mercury by oil.

Fig 5 presents some of the construction details of the level locator drive. The rod D connects to the heavier threaded rod F and it in turn engages a nut Q′. This nut is driven by a worm H which is directly connected to a revolution counter W′. The nut is between preloaded ball bearings within a case R′ which is securely fastened to the tube S′. The worm H is driven by a quick reversing, three-phase electric motor operating at approximately 1800 rpm. The pitch of the threaded rod F and the nut Q′ is such that one revolution of the counter corresponds to 0.00119 in. of travel of the level indicator E.

The two electrical leads from the level indicator are brought out of the rod D at the place where it engages the threaded rod F as shown in the enlarged view in Fig 5. Spring-loaded brush contacts carry the circuit to the knurled binding posts and flexible leads are used between them and convenient fixed connections. In addition, limit contacts are provided within the tube S′ to prevent the electrically driven worm H from moving the level indicator beyond the working range in the equilibrium cell and thus damaging the equipment.

To the lower end of the threaded rod F is attached the compensator rod G which was discussed. This consists of a rod of the same external cross section as the rod D. This passes through a packing gland into the cylinder P of Fig 1. The gland is of the type shown at N′ of Fig 4.

The valves and the fittings used for tubing connections are of the general type described in another paper.[3] All parts of the system containing mercury, aside from the equilibrium cell, are so designed as to possess a minimum of volume. This decreases to a satisfactory extent the influence of changes in room temperature and other factors upon the volume of the system during the attainment of equilibrium. However, such changes do not in themselves introduce any uncertainty in the volume measurements since the elevation of the mercury surface in the equilibrium cell is directly determined. This was not done in the equipment described earlier[2] and it then became necessary to avoid large changes in room temperature.

Measurement of Pressure. Earlier in-

vestigators[4–7] found that the rotating or oscillating piston-cylinder assembly probably affords the most precise convenient method for the determination of moderately high pressures. A pressure balance has been found to be a more convenient type of instrument than the "dead-weight tester." It is possible to obtain accurate indications of pressure quickly because longitudinal movement of the piston in reference to the cylinder can be kept very small.

It was shown by Beattie[8] and confirmed in this laboratory that it is preferable to calibrate the piston-cylinder combination rather than to attempt to determine accurately the effective area by direct measurement. Bridgeman[9] has determined with relatively high accuracy the vapor pressure of carbon dioxide at the freezing point of water saturated with air at atmospheric pressure. This physical state furnishes a convenient comparison standard for the determination of the "gauge constant" of the balance employed.

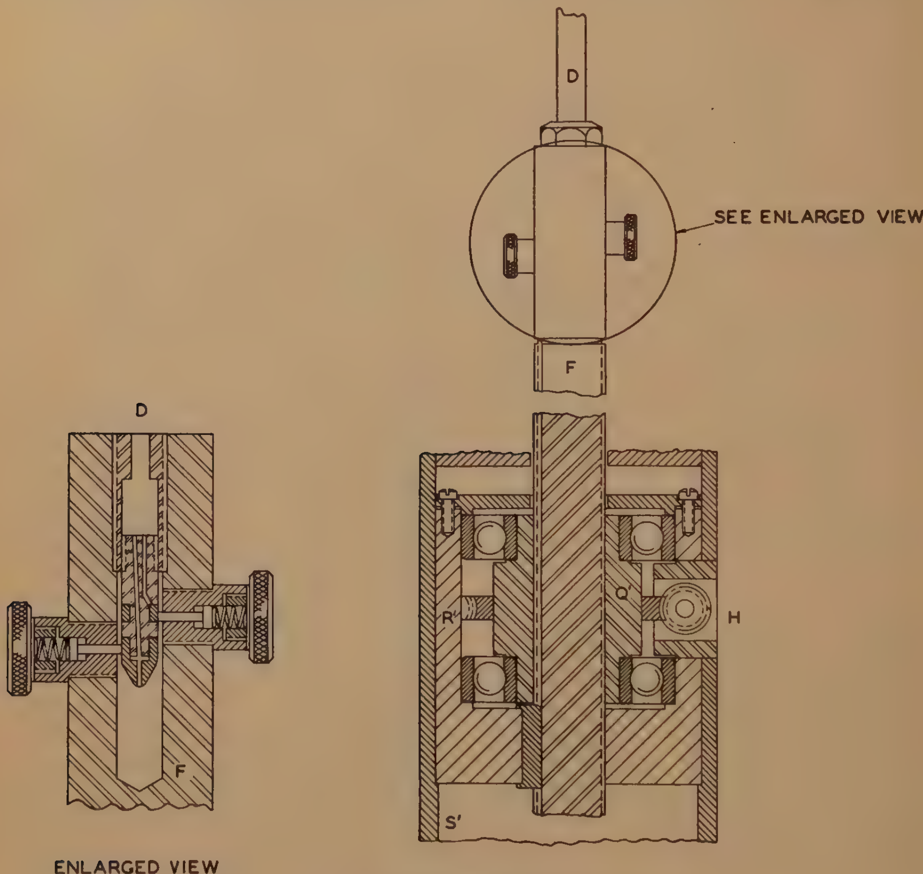

Fig 5—Level indicator drive.

This laboratory has described[3] one type of pressure balance utilizing the piston-cylinder combination developed and designed for use in connection with volumetric studies. A pressure balance of somewhat different design is used with the equipment described in this paper.

It is shown in the schematic assembly drawing of Fig 6.

In order that low pressures may be measured with somewhat greater precision two piston-cylinder combinations are provided, one having a diameter of ⅜ in. and the other of ³⁄₁₆ in. The several lever arms involved are so arranged that nominally there is a tenfold factor between the ranges of the two piston-cylinder combinations. The larger cylinder functions at pressures up to 1000 psi and the smaller one at pressures up to 10,000 psi. Each piston is provided with suitable arresting gear to allow it to be lowered individually upon its knife edge A. These knife edges are set in the upper edge of the lower beam B. This beam is suspended through two knife edges from the frame of the balance by the stirrup C. This stirrup is arranged to furnish 2° of freedom for the motion of the lower beam, thus avoiding difficulty from misalignment of the knife edge and the beam. Since the companion cylinder is slowly rotated to avoid binding, rotation of the piston is avoided by having the knife edge A engage a shallow V-notch in the lower end of the piston. The apex of this notch is constructed with a radius of approximately 0.005 in. and this permits the knife edge to react in the same fashion as if it were in contact with a plane surface.

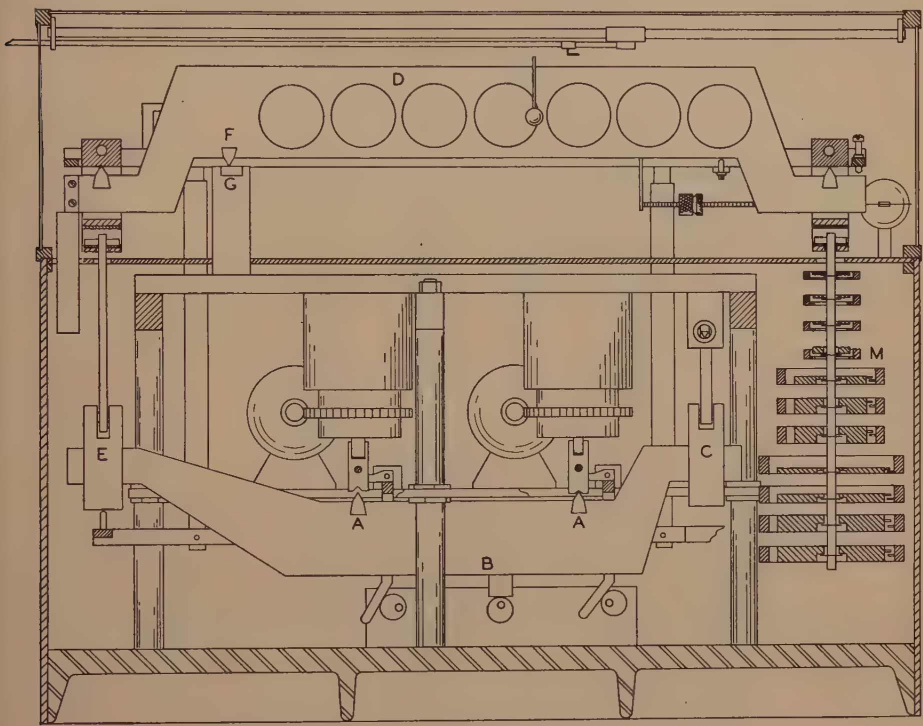

Fig 6—General arrangement of pressure balance.

The upper beam D and lower beam B are connected by means of a second stirrup E. This stirrup also provides the desired 2° of freedom in order that minor misalignment of the beam may not bring undue stresses upon the knife edges. The upper beam is supported upon a main knife edge F which bears upon a plane stellite surface G which is mounted

upon the frame of the balance. A conventional lifting mechanism is provided to permit realignment of the stirrups and the upper and lower beams.

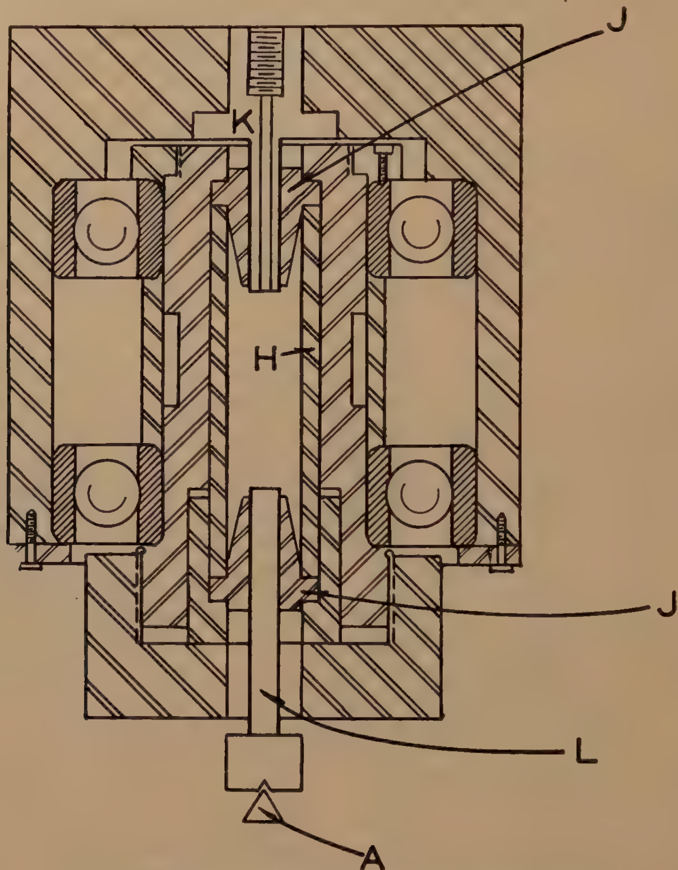

FIG 7—DETAILS OF PISTON-CYLINDER COMBINATION.

The design of the piston-cylinder combination is shown in Fig 7. The rotating cylinder H has two hardened sleeves J which fit tightly in its ends. A tubular piston K provides fluid communication with the space between the sleeves J. The actuating piston L acts upon the knife edge A. The cylinder H is rotated at a speed of approximately 45 rpm by means of a worm gear attached to the periphery. The tapered sleeves J are so designed as to yield a minimum of deformation of the accurately ground mating surfaces of the piston-cylinder combination. It is necessary to provide slightly larger clearances between the actuating piston and its mating sleeve than in the case of the tubular piston because of the radial deformation of the actuating piston at high pressures.

The weights shown at M in Fig 6 are distributed in sizes as in an analytical balance but were so arranged that each could be lowered upon or lifted from the beam hanger by the sliding of the corresponding wedge cam operated from outside the enclosing case. It is only necessary that the relative masses of the

several weights be adjusted within the desired tolerances so that there is a linear relation between pressure and the applied weight. The absolute values of the lengths of the lever arms, the effective diameter of the piston-cylinder combination, and the forces exerted by the weights are ascertained by calibration of the balance against the vapor pressure of carbon dioxide[9] at the ice point.

The pressure balance is connected to the equilibrium cell by means of tubing which is filled with a relatively nonviscous hydrocarbon liquid. In order to prevent this liquid from contaminating materials in the equilibrium cell, an oil-mercury interface is maintained in the trap X of Fig 1. A mechanical plunger Z′ is provided in order to compensate changes in the effective volume of the oil-filled system which result from variations in pressure and temperature. Before making a measurement with the balance the plunger position is adjusted to bring the oil-mercury interface in the trap to fixed position as indicated by an electric contact. The point of balance of the equipment shown in Fig 6 is ascertained by means of an optical lever which terminates upon a ground-glass screen on the front of the balance case. The sensitivity of this equipment is such that a variation in pressure of less than 0.2 psi can be detected at a pressure of approximately 8000 psi. Calibrations of this equipment obtained over a period of years indicate that the uncertainty in the absolute value of the pressure as referred to samples of carbon dioxide independently prepared is less than 0.05 pct. It appears then that the uncertainty of pressure measurements can safely be considered to be less than 0.2 psi or 0.15 pct, whichever corresponds to a larger uncertainty.

Temperature Measurements. The temperature of the equilibrium cell A of Fig 1 is controlled by means of the agitated oil bath U. The velocity of circulation of the oil is sufficiently great to keep temperature variations between the different parts of the bath less than 0.1°F. In addition, the oil bath is surrounded by a shield whose temperature is controlled manually so that the required energy input to the bath is 50 to 100 watts. This minimizes changes in the energy loss from the oil bath with changes in the ambient condition. In order to decrease temperature variations within the equilibrium cell A, an auxiliary heater is mounted just outside the bath upon the tube connecting the cell with the agitator drive K. The energy input to this heater is controlled manually so as to maintain a negligible temperature gradient along the tube where it leaves the oil bath. The extent of the temperature gradient is determined by means of a differential thermocouple whose junctions are mounted on the tube just inside and outside the oil bath, respectively.

The temperature of the oil bath is measured by means of a strain-free platinum resistance thermometer of the design developed by the National Bureau of Standards.[10] This resistance thermometer is compared at periodic intervals with the indications of a similar instrument which was calibrated by the Bureau of Standards. The resistance at the ice point is determined periodically and variations in this resistance are taken into account in the determination of the resistance corresponding to a particular temperature. The resistance of the thermometer is measured by means of a Mueller bridge utilizing the conventional four-lead connection to the resistance thermometer. The leads have relatively low resistance and are insulated to prevent rapid fluctuation in temperature.

It appears that the temperature of the oil bath can be measured within 0.1°F relative to the international platinum scale for temperatures between 30° and 460°F. However, because of thermal

leakage from the equilibrium cell along the metallic leads from it, it is doubtful that the temperature of the contents of the equilibrium cell is known within

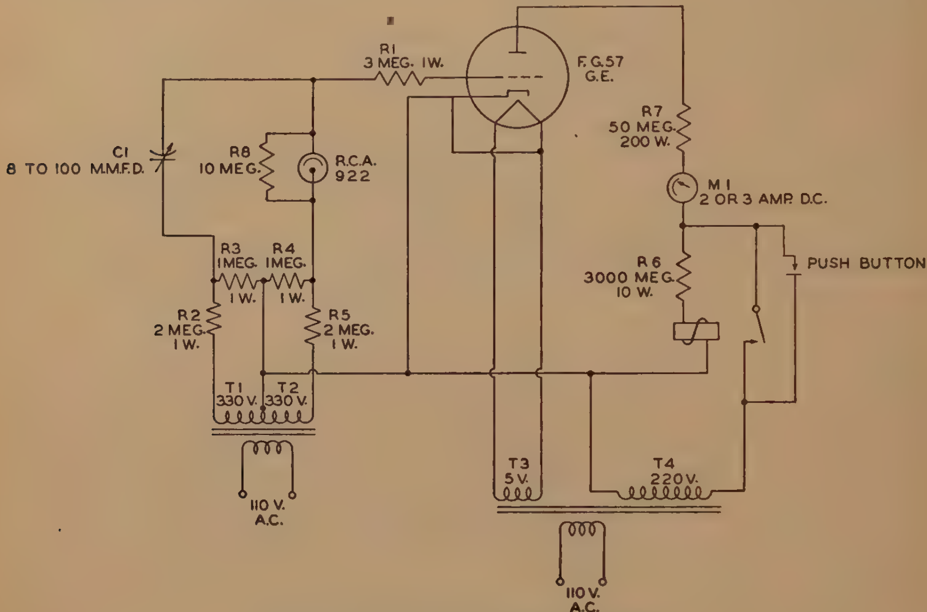

FIG 8—TEMPERATURE CONTROL CIRCUITS.

0.2°F relative to the international platinum scale.

The energy input to the oil bath U of Fig 1 is controlled by means of a second platinum resistance thermometer in the bath. Any lack of balance developing in the thermometer bridge circuit causes deflection of a galvanometer. The light beam from the galvanometer mirror is thus brought upon a photoelectric cell with gradually increasing effect upon a thyratron circuit controlling the electrical energy input to the oil bath. This provides modulation of energy input rather than an on-or-off type of control which tends to cause hunting. The details of this circuit are shown in Fig 8. The light beam from the control galvanometer should not be sharply focussed on the photoelectric cell in order to avoid excessive sensitivity within the control circuit. The variation in bath temperature after thermal equilibrium has been obtained is less than 0.05°F. The rate of response of the control circuit to minor temperature variations can be modified by suitable adjustment in the control circuit or in the intensity of the light beam.

In order to obtain temperatures below ambient conditions an auxiliary circulating system was installed through which a portion of the oil in the bath U was circulated. This oil was cooled by expanding dichloro-difluoromethane into a coil immersed in the relatively turbulent oil immediately downstream from an axial-flow circulating pump. In order to obtain temperature control under these circumstances, more thermal energy was withdrawn through the auxiliary circulating system than was necessary to decrease the temperature to the desired value. The additional thermal energy was introduced through the normal electrical control system. It was found that a fixed setting of an expansion valve sufficed

to provide uniform rate of energy withdrawal by the auxiliary circulating system.

Measurements of Volume. The determination of the effective volume of the equilibrium cell A of Fig 1 is carried out by measuring the elevation of the mercury surface within this chamber as was indicated earlier. In the construction of the equipment, every effort was made to insure a uniform diameter of the working cell and cross section of the spiral agitator. The over-all calibration of the cell is carried out by withdrawing mercury and determining the change in elevation of the surface as a function of the weight of mercury withdrawn. The residual volume of the cell above positions where the elevation of the mercury interface may be measured by means of the level indicator H is determined by the introduction of hydrocarbon liquids of known specific weights.

The total volume V of the equilibrium cell occupied by the sample is then determined by application of the following equation:

$$V = K(N_o - N_{Hg}) \qquad [1]$$

in which $K = \phi(T,P)$
$N_o = \phi'(T,P)$
N_{Hg} = reading of counter W'

The values of K and N_o vary slightly with pressure and the appropriate numerical quantities are obtained by residual graphical interpolation of the calibrations described above. An over-all calibration of the instrument is accomplished in terms of the known pressure-volume-temperature relations of methane.[11] The agreement of these data with those of other investigators as recently correlated[12] indicates that this method permits as accurate evaluation of the total volume of the system as is represented by the experimental results obtained at other laboratories. No attempt is made to correct the total volume of the system as determined by Eq 1 for the variation of the contact angle between mercury and stainless steel resulting from changes in pressure in the cell. Changes in this contact angle with temperature are taken into account by determining N_o at several temperatures and with different typical materials.

Addition of Materials. In addition to measurements of pressure, temperature, and total volume, it is necessary to determine with comparable accuracy the weight of material introduced into the equilibrium cell A.

In the case of liquid samples having appreciable bubble-point pressures but containing comparatively nonvolatile components, a previously weighed pressure vessel Z containing the liquid sample is attached to the fitting shown in Fig 1 at O. The cell together with connecting tubing and valve assembly is evacuated. The connecting lines are filled from another supply of sample through the valve N bringing the pressure within this assembly to that within the pressure vessel. Valves O and J are then opened into the evacuated cell A and mercury is supplied to the lower part of the auxiliary pressure vessel Z until the desired amount of liquid sample has been transferred to the equilibrium cell. The valve J is then closed and the pressure within the vessel Z and the connecting tubing is raised or lowered to the original value by the introduction or withdrawal of mercury. The valves at the top and bottom of the pressure vessel are closed and it is removed from the fitting O. From the gain in weight of the pressure vessel and a knowledge of the specific weights of the mercury and the liquid being added it is possible to compute the quantity of liquid sample introduced into the equilibrium cell.

In the case of single-component volatile liquids the material is introduced through the valve L by following a weighing bomb technique.[3] The purified sample is

distilled into a carefully evacuated weighing bomb. The bomb is connected to the fitting at valve L and the intervening lines are evacuated. The weighing bomb valve and the cell valve I are opened and the desired amount of the volatile liquid is distilled from the bomb into the equilibrium cell A. The valve I is then closed and the temperature of the weighing bomb is reduced by immersing it in liquid air. This recondenses in the bomb substantially all of the material from the connecting line and in the body of the valve H. Investigations involving successive introduction and withdrawal of materials such as *n* butane, the bomb being disconnected and replaced meanwhile, show that such operations can be carried out with an uncertainty in the weight of sample introduced of less than five milligrams.

Normally gaseous components such as methane are added by withdrawals from the pressure vessel Q of Fig 1. This vessel is immersed in an oil bath R in which agitation is provided by a circulating pump and the temperature is controlled with an uncertainty of approximately 0.1°F at a convenient value slightly above room temperature by means of a mercury-in-glass regulator. The pressure within the chamber Q is measured through the oil-mercury connecting system indicated in Fig 1. The oil-mercury interface of this system is held at a fixed point within the vessel S by suitable manipulation. The tubing line connecting the pressure vessel Q and the equilibrium cell A is maintained at the same temperature as the vessel Q by circulating oil from the bath R through a conduit surrounding the tubing. The chamber Q is calibrated by measuring the change in pressure corresponding to a change in weight of the same gas as is under investigation contained in chamber Q. For this purpose the change in weight is determined by withdrawing a portion of the gas from chamber Q into a weighing bomb attached at valve L. During calibration, the oil baths U and R are kept at the same temperature.

Volume of Liquid. The foregoing discussion has presented methods for the measurement of the total volume of the system as a function of pressure and temperature. In studies of the volumetric behavior of heterogeneous, multicomponent systems it is advantageous to determine in addition the volume of the liquid phase as a function of state. This is accomplished in the equipment described by means of the platinum wire which constitutes a part of the movable head shown in Fig 2. Sufficient electrical energy is passed through the wire so as to raise its temperature approximately 1°F above that of the surroundings. Owing to the low weight of this fine wire, the amount of this energy input is too small to affect the state of the system appreciably. The electromotive force across the wire is determined by a suitable potentiometer circuit. Upon transferring the wire from the gas to the liquid phase its temperature decreases and a corresponding change occurs in the electromotive force existing across the leads to the hot wire. The change in electromotive force is indicated by the galvanometer in the potentiometer circuit. It is found possible to duplicate the measurement of the elevation of the gas-liquid interface with an uncertainty of approximately 0.002 in.

The effect on liquid volume measurements of the difference in vertical elevation between the hot wire and the mercury level detecting pin E of Fig 2 and that of the contact angle of mercury and liquid on the cell wall are combined in the constant c of the following equation:

$$V_l = K(N_l - N_{Hg} + c) \qquad [2]$$

This constant is evaluated from readings of the position of the hydrocarbon gas-liquid interface N_l and the mercury level reading N_{Hg} at conditions for which V_l

is known from data on the sample being used for the calibration. These calibrations were carried out with a variety of liquids and from this it is possible to determine the value of c for the liquid being studied.

in the determination of the volume of the liquid phase of the hydrocarbon system and this results from the wetting of the walls of the steel cell with the liquid phase and a possible retention of liquid below the hydrocarbon-mercury interface. A decrease in the elevation of the mercury-hydrocarbon interface of 10 in. causes approximately 3×10^{-5} cu ft (0.75 cc) of liquid to be left adhering to the walls of the cell above the mercury when the hydrocarbon has a viscosity of 29 centipoises. Approximately 1×10^{-5} cu ft (0.25 cc) of this oil was retained below the surface of the mercury upon an increase in the elevation of the hydrocarbon-mercury interface of 10 in. In the case of a nonviscous material such as n-butane this retention was negligible. The segrega-

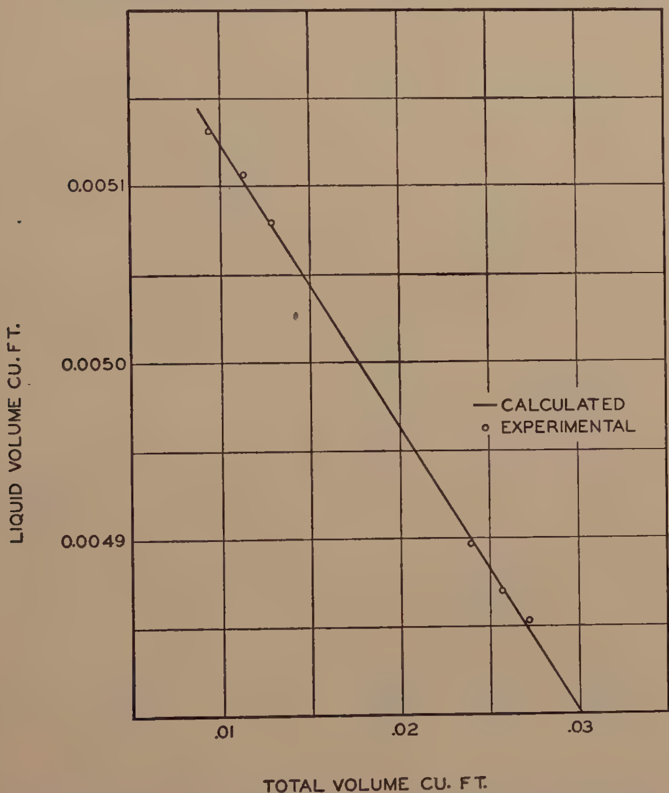

FIG 9—COMPARISON OF MEASURED AND ACTUAL LIQUID VOLUMES.

The experimental and calculated values of the volume of the liquid phase of the heterogeneous n-butane system are presented in Fig 9 in relation to the total effective volume of the equilibrium cell. These data indicate an uncertainty in the determination of the volume of the liquid phase of approximately 5×10^{-6} cu ft (0.14 cc) irrespective of the total volume of liquid phase involved. The fractional uncertainty of measurement is greatest when small volumes of liquid phase are involved.

There exists still another uncertainty

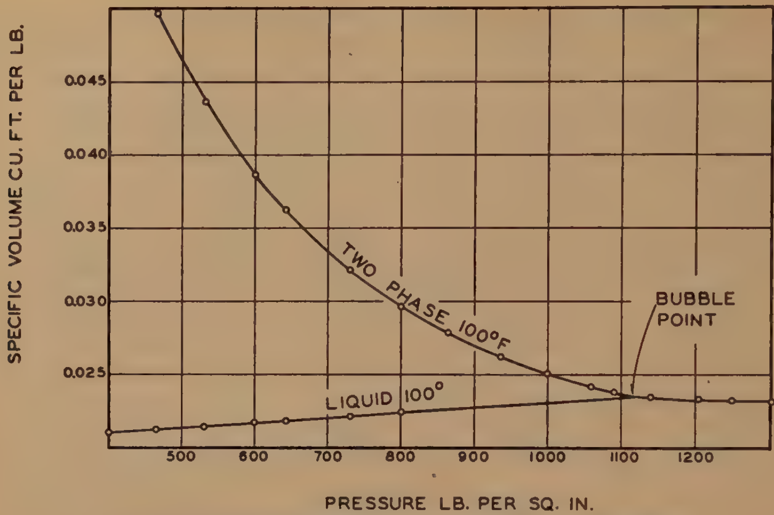

FIG 10—VOLUMETRIC BEHAVIOR OF NATURAL GAS-OIL MIXTURE.

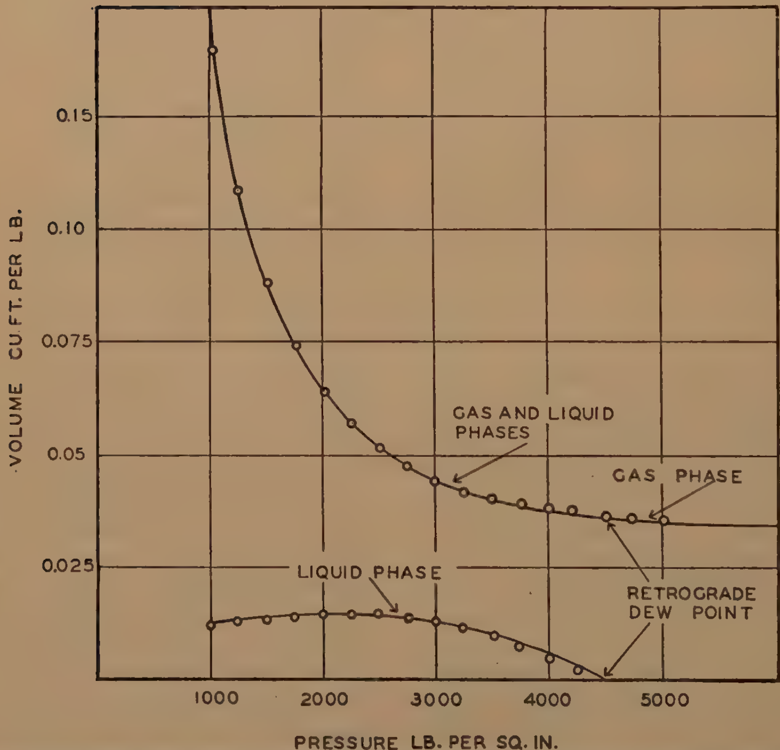

FIG 11—VOLUMETRIC BEHAVIOR OF HYDROCARBON MIXTURE SHOWING RETROGRADE DEW POINT.

tion of a portion of the system exerts a measurable effect upon the composition of the heterogeneous hydrocarbon system and also upon the measured total volume. However, in the case of material with relatively low viscosity such as the hydrocarbons of lower molecular weight it does not appear that the uncertainty in measurement of the total volume of the system will exceed approximately 0.5 pct under the most adverse conditions normally encountered in the volumetric studies.

Table 1 presents an estimate of the uncertainties of measurements of total volume, liquid volume, temperature, pressure and weight when utilizing the equipment and procedures described herein. This estimate does not take into account the uncertainty in the determination of the total volume and weight of a system resulting from the wetting of the walls of the equilibrium cell below the mercury-hydrocarbon interface.

TABLE 1—*Estimated Uncertainties of Measurements Made with Equipment and Procedures Described*

MEASUREMENT	ESTIMATED UNCERTAINTY
Total volume	0.5 pct
Liquid volume	0.005 cu in
Temperature	0.2° F
Pressure	0.2 psi or 0.15 pct
Weight	0.2 pct

In order to illustrate the data obtained with the equipment described, Fig 10 presents measurements of the total volume and the volume of the liquid phase of a unit weight of a mixture of naturally occurring hydrocarbons which reaches bubble point within the range of pressures investigated at the temperature in question. The limitation of ability to measure the volume of the liquid phase as bubble point is approached is indicated by the absence of experimental points upon the liquid volume-pressure curve at pressures in the vicinity of bubble point. Fig 11 shows similar information for a mixture which reaches a retrograde dew point upon isothermal compression at the temperature in question. These data show the sequence of gradual increase followed by decrease in liquid volume as the pressure is continuously increased. The composition of each of the mixtures shown in Figs 10 and 11 is recorded in Table 2.

TABLE 2—*Composition of Hydrocarbon Mixtures*

Component	Composition of Mixture for Fig 10		Composition of Mixture for Fig 11	
	Weight Fraction	Mole Fraction	Weight Fraction	Mole Fraction
Methane	0.0520	0.2632	0.3548	0.7155
Ethane	0.0191	0.0517	0.0768	0.0826
Propane	0.0424	0.0783	0.0717	0.0526
Isobutane	0.0181	0.0254	0.0197	0.0110
n Butane	0.0439	0.0615	0.0400	0.0222
Isopentane	0.0252	0.0283	0.0182	0.0081
n Pentane	0.0304	0.0343	0.0190	0.0085
Hexanes and heavier[a]	0.7678	0.4553	0.3894	0.0919
Carbon dioxide	0.0011	0.0020	0.0104	0.0076

[a] Average molecular weight 137.1.

ACKNOWLEDGMENT

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Calculated Effect of Pressure Maintenance on Oil Recovery

By Robert L. Hoss,* Junior Member AIME

(New York Meeting, March 1947)

Abstract

The application of Muskat's differential equations for predicting the performance of a solution gas-drive reservoir to the Fullerton field indicates that a recovery may be expected of 14,030 bbl per acre under primary depletion, and 15,910 and 17,190 bbl per acre, respectively, under the two pressure-maintenance programs analyzed.

In this analysis it is assumed that fluid properties are the same throughout the reservoir, that the core data used are typical of the Clear Fork limestone in the locality, and that injected gas is completely diffused through the pay zones.

The economic study of the three recovery programs considered indicates that the one in which 60 pct of the produced gas is returned to the formation is the most profitable.

Introduction

The purpose of this paper is to consider the effect of pressure maintenance by gas injection on the ultimate recovery of oil from a solution gas-drive reservoir. This prediction of reservoir behavior is the result of calculations based on the equations presented by M. Muskat in the *Journal of Applied Physics*, March 1945.

Reservoir

The reservoir analyzed is the Fullerton field in Andrews County, West Texas. It is situated on a broad anticlinal structure with approximately 330 ft of closure, and extends approximately eight miles north and south and five miles east and west. The areal extent is taken as 16,642 acres.

The producing horizon is the Lower Clear Fork limestone of Permian age, occurring at depths from 6650 to 7350 ft. It is divided into four zones. For the purposes of this study, the fluid characteristics in all zones are assumed to be the same. Therefore an equivalent zone is assumed of thickness equal to the sum of the thicknesses of the four zones, or an average of 216 ft.

The reservoir contains 3,586,991 acre feet of producing limestone, with an initial volume of stock tank oil in place of 918,403,100 bbl.

The average connate water saturation is 24.0 pct. The permeability ranges from 6.7 md. to 12.6 md., and the porosity ranges from 7.7 pct to 11.4 pct, except for occasional cavernous streaks. Based on these values, the limestone may be considered intergranular.[1]

Production histories and material-balance studies have indicated that the driving mechanism is solution gas. Water levels have been established.

Theory

It is possible to express mathematically the change in residual oil saturation with pressure decline in a solution gas-drive reservoir as being equal to the change in the physical properties of the fluids present in the reservoir as this pressure decline occurs. Essentially these equations, in differential form as presented by M. Muskat,[2] express quantitatively the instantaneous net effect

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[1] References are at the end of the paper.

of the simultaneously occurring changes in reservoir-volume factor, oil and gas viscosity, gas solubility in oil, and gas density, and the accompanying changes in permeability to oil and gas.

These equations and their utility can be best understood by study of the derivation contained in the original Muskat reference. The final form shown here lends itself primarily to numerical solution,

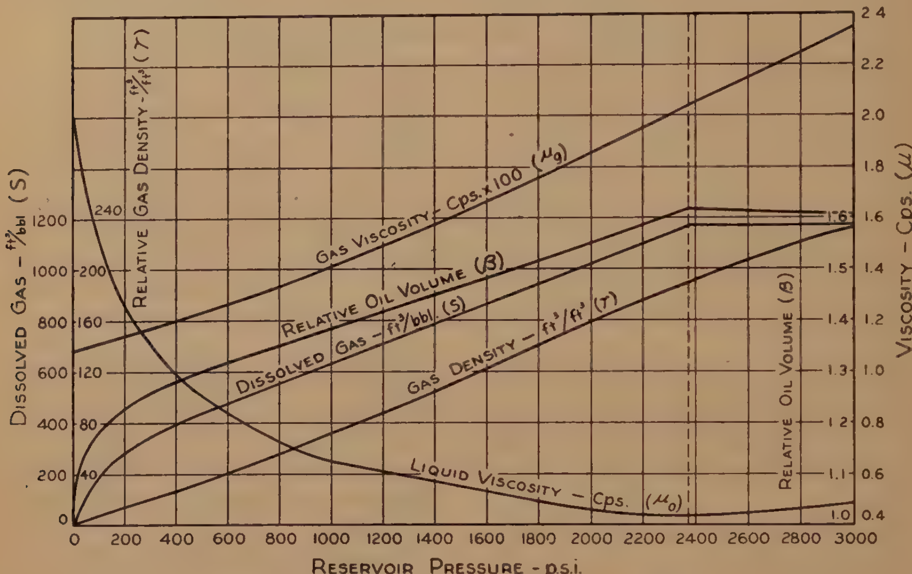

Fig 1—Reservoir fluid characteristics.

rather than any expression of functional relationships.

The equation for the change in residual oil saturation as pressure declines during primary depletion is:

$$\omega(\rho_o, p)\frac{d\rho_o}{dp} = \rho_o\lambda(p) + (1-\rho_w-\rho_o)\epsilon(p) + \rho_o\psi(\rho_o)n(p) \quad [1]$$

If gas is injected to arrest the pressure decline, the following equation applies:

In arriving at these expressions the following assumptions are made: The connate water saturation remains constant; any gas cap is nonexpanding; and any gas injected is uniformly diffused through all of the producing horizon.

$$\frac{d\rho_o}{dp} = \frac{\rho_o\lambda + [H(1-\rho_w-\beta\rho_{oi}) + (1-\rho_w-\rho_o)]\epsilon - H\rho_{oi}\frac{d\beta}{dp} + \left(\psi - \frac{rR}{\alpha}\right)\rho_o n}{1+\frac{\mu_o}{\mu_g}\left(\psi-\frac{rR}{\alpha}\right)} \quad [2]$$

where:

$$\alpha(p) = \gamma\beta\frac{\mu_o}{\mu_g},\ \omega(\rho_o, p) = 1 + \frac{\mu_o}{\mu_g}\psi(\rho_o),$$

$$\lambda(p) = \frac{1}{\gamma\beta}\frac{dS}{dp}$$

$$\epsilon(p) = \frac{1}{\gamma}\frac{d\gamma}{dp},\ n(p) = \frac{\alpha(p)}{\beta^2\gamma}\frac{d\beta}{dp}$$

Calculations

These differential equations can be integrated numerically by assuming the rate of change of the various properties with pressure decline to remain constant over some short pressure interval such as 100 psi,

as was used in these calculations. In assuming this pressure decrement, the differential quantities become delta quantities and can be obtained as slope values directly from the curves of these properties versus introduced at most pressures. In addition, average values over the assumed pressure decrement in question must be obtained from the curves for gas and liquid viscosities.

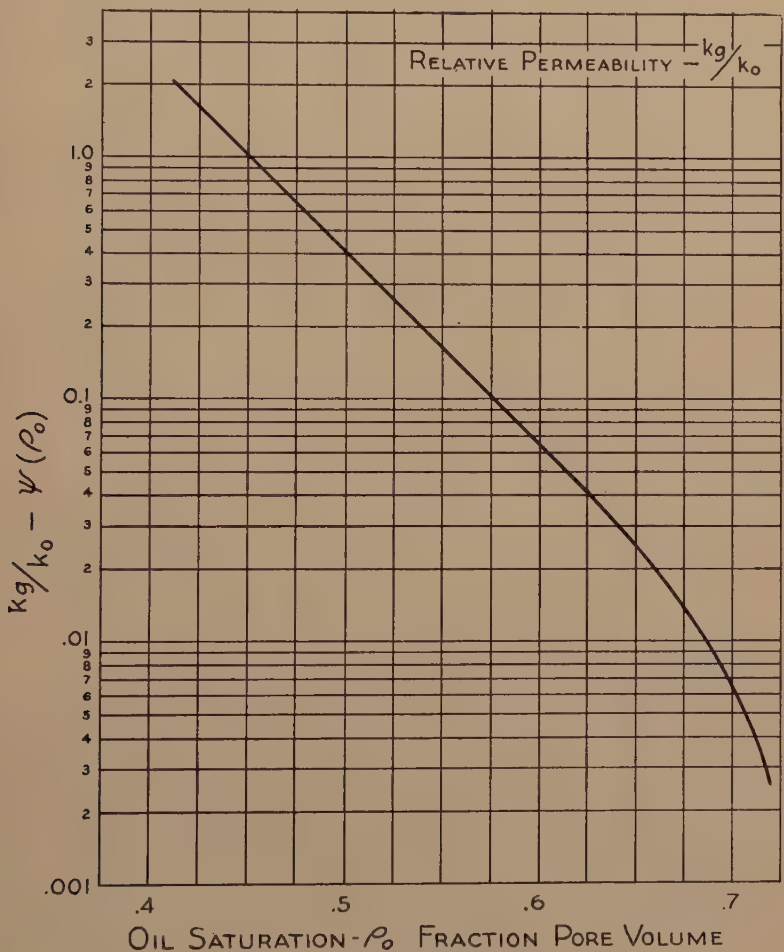

FIG 2—RELATIVE PERMEABILITY.

pressure, as shown in Fig 1 for the Fullerton fluids. These slope values are required for the pressure rate of change of volume factor, gas solubility, and relative gas-density. This assumption of a linear relationship is true throughout most of the pressure decline with the exception of the 500 psi to 0 psi interval. Hence no significant error is

To minimize the errors inherent in this stepwise-integration procedure, all values of the physical properties of the fluids varying with pressure, as shown in Fig 1, were taken at the mid-point of each successive pressure interval of 100 psi.

A value of the relative-permeability ratio for the residual saturation existing at

the beginning of the particular pressure decrement in question is then taken from the curve in Fig 2. This curve is assumed typical of the Clear Fork limestone, and is based results in a new residual oil saturation which actually exists along with its corresponding k_g/k_o value only at the beginning of the next ensuing pressure decrement.

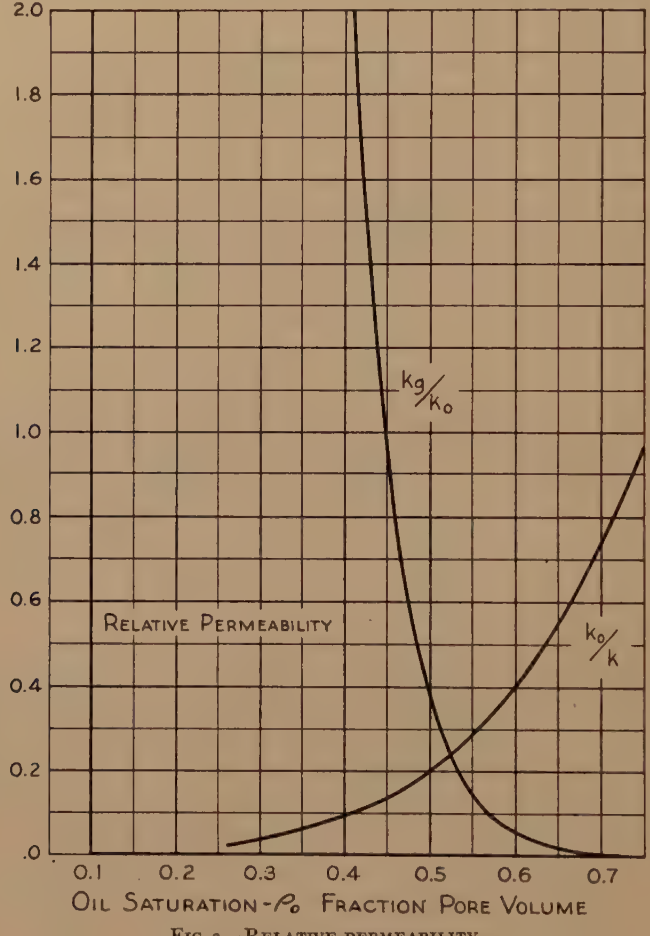

FIG 3—RELATIVE PERMEABILITY.

on the relative permeability values as calculated from the observed performance of several Permian limestone reservoirs. The curve is shown on Cartesian coordinates in Fig 3.

The end result of the calculations over any pressure decrement is a change in the residual oil saturation in the reservoir. The subtraction of the change in residual saturation from the previous value of saturation This k_g/k_o value is assumed to hold over the next pressure decrement, for purposes of calculation.

By following the procedure outlined, the equations were evaluated in stepwise fashion for successive 100 psi intervals beginning with the saturation pressure of 2370 psi and continuing down to the abandonment pressure. The abandonment pressure is reached when the reduction in

volume factor becomes equivalent to the reduction in residual oil saturation.

The average gas-oil ratio during each pressure interval was determined in the calculations are shown in Fig 4, where reservoir pressure decline and gas-oil ratio are plotted against cumulative recovery in percentage of pore volume.

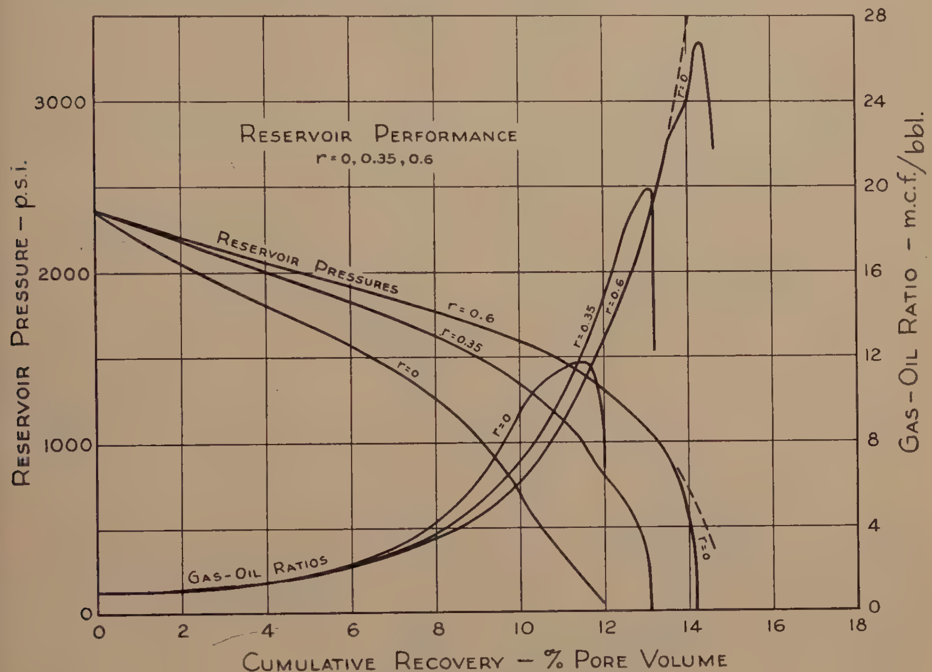

Fig 4—Reservoir performance.

conventional manner[3] from the relative permeability and fluid property data just mentioned.

Sample calculations appear in the appendix for determining the change in residual oil saturation during a 100 psi decline in reservoir pressure and the average gas-oil ratio during that decline, for both primary recovery and pressure maintenance where $r = 0.6$.

Results

The equations were applied to the Fullerton reservoir in this manner and a prediction of the reservoir performance obtained for primary depletion and two separate pressure-maintenance programs, where 35 pct and 60 pct of the produced gas were injected, respectively. The results of these

In the cases of pressure maintenance, the decrease in the rate of pressure decline is shown with the greatest arrestment being realized where 60 pct of the gas is returned to the reservoir. An early drop in gas-oil ratio results from the calculations in the region of 1 pct pore volume recovered, although it does not show here because of the small scale employed. This phenomenon is caused by the decrease in the volume of gas held in solution as the saturation pressure is passed and before a significant permeability to gas has developed.

The close agreement of the three gas-oil ratio curves to 6 pct pore volume cumulative recovery is explained by the fact that the effect of decreased permeability to gas in the cases of pressure maintenance is offset by the increased volume of gas held

in solution at those higher pressures. Between 6 and 13 pct pore volume cumulative recovery, the beneficial effect of pressure maintenance is again evident, in that the more intense the pressure-maintenance program, the lower the gas-oil ratio. That is, with pressure maintenance at the same recovery as realized under primary depletion the volume factor is higher causing the gas permeability and hence the gas-oil ratio to be lower. Also the increased oil mobility at these higher degrees of saturation facilitates movement of the oil through the formation, and thus assists in reducing gas-oil ratios. In the region beyond 11 pct pore volume cumulative recovery, the gas-oil ratio values for pressure maintenance rise rapidly because of the rapidly increasing magnitude of the relative permeability ratio and the larger standard volumes of gas contained in the reservoir.

The case of 35 pct of the produced gas being returned to the reservoir was studied since it is the largest percentage of the produced gas which can be continuously injected without exceeding an economic limit of 20,000 cu ft per barrel sometime during the life of the reservoir. In the case of 60 pct of the produced gas being injected pressure maintenance was discontinued when the gas-oil ratio reached 22,000 cu ft per barrel, and the equations for primary depletion used to evaluate this program for the remainder of its producing life.

The data used in plotting the curves in Fig 4 are summarized in Table 1.

Fig 5 shows the decline in productivity index as cumulative recovery increases. The productivity-index factor used is directly proportional to the reservoir productivity index, all other dimensional quantities being constant. The values of the relative permeability and absolute viscosity at the various pressures and corresponding residual saturations were taken from the oil viscosity curve of Fig 1 and the curve of the relative permeability to oil shown in Fig 3.

The decline of the three curves in Fig 5 is solely a function of the decreasing permeability to oil and the increasing oil viscosity, as recovery continues. The relative position of the three curves shows again the beneficial effect of pressure maintenance.

Table 1—*Performance Data*

Recovery Method	Cumulative Oil Production			Average Gas-oil Ratio, Cu Ft/Bbl	Maximum Gas-oil Ratio, Cu Ft/Bbl	Abandonment Pressure, Psig
	Pore Volume, Pct	Initial Oil in Place, Pct	Bbl Per Acre			
$r = 0$	12.6	26.5	14,300	5,595.0	11,810.0	50.0
$r = 0.35$	13.7	28.9	15,910	9,262.0	19,900.0	300.0
$r = 0.60$	14.8	31.2	17,190	13,441.0	26,800.0	300.0

The results shown in Table 1 and Fig 4 are only as accurate as the fundamental data available and the method employed. The sources of error present in the numerical stepwise solution of the fundamental equations have been mentioned previously.

The fluid in the lower part of the third zone and all of the fourth zone has a saturation pressure of 910 psi as compared with a saturation pressure of 2370 psi for the first, second, and upper third zones. This upper section, having the fluid with the higher saturation pressure, contains approximately 80 pct of the stock tank oil in place and comprises the same fraction of the total reservoir volume. This fact is the basis for the simplifying assumption that the characteristics of the fluids are everywhere the same as those of the fluids found in the upper section.

The Clear Fork limestone productive

section is not uniform and the volumes of gas to be injected must be adjusted upward to allow for the expected gas channeling through the cavernous and more porous sections. The selection of some conformance factor is difficult at best, and introduces some uncertainty into prediction of gas volumes required to accomplish pressure maintenance as planned. However, if the reservoir pressure decline is controlled, the ultimate recovery should be very near the calculated value.

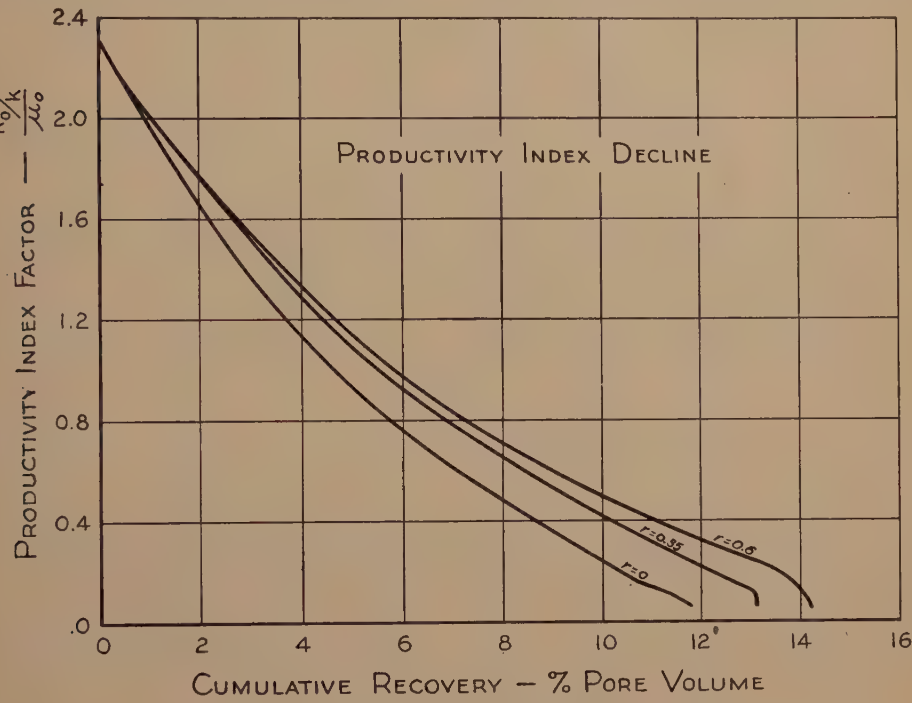

FIG 5—PRODUCTIVITY INDEX DECLINE.

ECONOMIC ANALYSIS

The reservoir performance was placed on a time basis using present and expected future allowable as set forth by the Texas Railroad Commission and an estimate of the number of producing wells. Knowing the reservoir pressure decline, cumulative production, and average gas-oil ratio, all as a function of time, the compressor program and other expense and income items were anticipated for each withdrawal program studied.

The results of this comparative economic analysis are summarized in Fig 6 where income is shown as a function of the percentage of the produced gas returned to the reservoir.[4]

CONCLUSIONS

The slope of the lowest curve in Fig 6 continues to decrease as more gas is injected, indicating that injection above 65 pct of the produced gas into the reservoir would yield no increase in net income, even though the gross income continued to increase. Therefore, it is concluded that of the three pressure-maintenance programs studied, the one in which 60 pct of the produced gas is injected into the reservoir is the most profitable.

Acknowledgments

The author wishes to express his appreciation to members of the Fullerton Operators Committee for permission to publish this paper and to the Fullerton Engineering Committee for making available the basic data but wishes to emphasize that the paper does not purport to be an official conclusion of either of these two committees nor of any particular operator or operators represented upon the committees.

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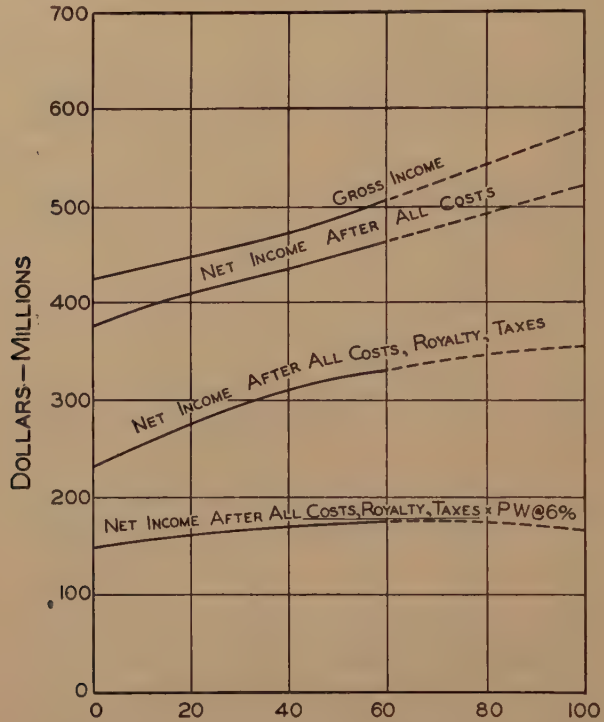

FIG 6—EFFECT OF PRESSURE MAINTENANCE ON INCOME.

Nomenclature

o,g,ω—subscripts denoting oil, gas, and water, respectively

p—pressure, psi

k—permeability in darcys

μ—viscosity in centipoises

R—total or gross surface gas-oil ratio, cu ft per cu ft

S—solubility of gas in oil, cu ft per cu ft (expressed as cu ft per bbl in Fig 1)

β—volume factor, reservoir volume occupied by a unit volume of oil at standard surface conditions

γ—relative gas density, cu ft per cu ft, or the volume of gas at standard conditions required to occupy 1 cu ft of space at reservoir conditions

ρ—residual saturation, expressed as the decimal fraction of the pore volume occupied by the fluid

$\alpha,\lambda,\epsilon,n$—numerical quantities, functions of pressure, with units of $1/p$ or sq in per lb

$\psi(\rho_o)$—relative permeability ratio, k_g/k_o

r—decimal fraction of the produced gas returned to the reservoir

H—ratio of the thickness of the gas cap to the thickness of the oil zone

ρ_{oi}—initial residual oil saturation in the gas cap, expressed as the surface equivalent

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Appendix

Sample Calculations

1. A 100 psi pressure decrement is taken at random as from 1600 psi to 1500 psi, for the purposes of illustration.

The following data at 1550 psi are obtained from Fig 1:

$$\gamma = 118 \text{ ft}^3/\text{ft}^3$$
$$\beta = 1.475$$
$$\mu_o = 0.54 \text{ cps}$$
$$\mu_g = 0.0165 \text{ cps}$$
$$S = \frac{850}{5.62} = 151 \text{ ft}^3/\text{ft}^3$$
$$\frac{dS}{dp} = 6.92 \times 10^{-2}$$
$$\frac{d\gamma}{dp} = 10.78 \times 10^{-2}$$
$$\frac{d\beta}{dp} = 1.7 \times 10^{-4}$$

2. The final equation to be solved, for the case of *primary recovery* is:

$$\frac{d\rho_o}{dp} = \frac{\rho_o\lambda(p) + (1 - \rho\omega - \rho_o)\epsilon(p) + \rho_o\psi(\rho_o)n(p)}{\omega(\rho_o, p)} \qquad [1]$$

(1) The parts of Eq 1 are evaluated separately.

$\rho_o = 0.61$ = the value existing at 1600 psi and assumed to hold over the next 100 psi pressure drop, until the next ensuing $\Delta\rho_o$ can be evaluated for the subsequent pressure decrement, or 1600 to 1500 in this case.

$$\lambda(p) = \frac{1}{\gamma\beta}\frac{dS}{dp}$$
$$= \frac{1}{118 \times 1.475} \times 6.92 \times 10^{-2}$$
$$= 3.98 \times 10^{-4}$$
$$(1 - \rho_\omega - \rho_o) = \rho_g = 0.76 - \rho_o = 0.15$$
$$\epsilon(p) = \frac{1}{\gamma}\frac{d\gamma}{dp}$$
$$= \frac{10.78 \times 10^{-2}}{118} = 9.13 \times 10^{-4}$$
$$\psi(\rho_o) = \frac{k_g}{k_o} @ \rho_o$$
$$= 0.61, \text{ from Fig 2} = 0.0525$$
$$\alpha(p) = \gamma\beta\frac{\mu_o}{\mu_g}$$
$$= 118 \times 1.475 \times \frac{0.54}{0.0165} = 5690$$
$$n(p) = \frac{\alpha(p)}{\beta^2\gamma}\frac{d\beta}{dp}$$
$$= \frac{5690 \times 1.7 \times 10^{-4}}{(1.475)^2 \times 118}$$
$$= 37.7 \times 10^{-4}$$
$$\omega(\rho_o, p) = 1 + \frac{\mu_o}{\mu_g}\psi(\rho_o)$$
$$\omega(\rho_o, p) = 1 + \frac{0.54 \times 0.0525}{0.0165} = 2.72$$

(2) Substituting the values from (1) in the final equation:

$$\frac{d\rho_o}{dp} = \frac{(0.61)(3.98 \times 10^{-4}) + (0.15)(9.13 \times 10^{-4}) + (0.61)(0.0525)(37.7 \times 10^{-4})}{2.72}$$
$$= 1.84 \times 10^{-4}$$

$$\Delta\rho_o = (1.84 \times 10^{-4})(100) = 0.0184$$

$\therefore$ the new ρ_o @1500 psi $= 0.61 - 0.0184$
$= 0.592$

(3) Gas-oil ratio calculation:

$$R = S + \alpha(p)\psi(\rho_o)$$
$$R = 151 + 5{,}690 \times 0.0525$$
$$R = 151 + 299 = 450$$
$$R = 450 \times 5.62 = 2530 \text{ ft}^3\text{/bbl}$$

where $\psi(\rho_o) = k_g/k_o$ @ $\rho_o = 0.547$, from Fig 2 $= 0.168$

(3) $\rho_o = 0.547$
$r = 0.6$

$$\left(\psi(\rho_o) - \frac{\gamma R}{\alpha(p)}\right) = \left(0.168 - \frac{0.6 \times 1106}{5690}\right)$$
$$= 0.051$$
$$(1 - \rho_w - \rho_o) = 0.76 - 0.547 = 0.213$$

(4) Substituting in the final equation as explained in step 3 Eq 1:

$$\frac{d\rho_o}{dp} = \frac{(0.547)(3.98 \times 10^{-4}) + (0.231)(9.13 \times 10^{-4}) + (0.051)(0.547)(37.7 \times 10^{-4})}{1 + \dfrac{(0.54)}{0.0165}(0.051)}$$

(4) Cumulative recovery @ reservoir pressure of 1600 psi.

$$\text{cum. rec.} = \left(\frac{\rho_o}{\beta}\right)_i - \left(\frac{\rho_o}{\beta}\right)$$

$$\text{cum. rec.} = \frac{0.76}{1.60} - \frac{0.61}{1.485} = 0.059$$

3. The final equation to be solved, for the case of *pressure maintenance* is:

$$= 1.94 \times 10^{-4}$$
$$\Delta\rho_o = (1.94 \times 10^{-4})(100) = 0.0194.$$

$\therefore$ the new ρ_o @ 1500 psi $= 0.547 - 0.0194$
$= 0.528$

(5) Cumulative recovery @ reservoir pressure 1600 psi

$$\text{cum. rec.} = \left(\frac{\rho_o}{\beta}\right)_i - \left(\frac{\rho_o}{\beta}\right)$$
$$= 0.47 - \frac{0.547}{1.485} = 0.099$$

$$\frac{d\rho_o}{dp} = \frac{\rho_o\lambda(p) + [H(1 - \rho_w - \beta\rho_{oi}) + (1 - \rho_w - \rho_o)]\epsilon(p) - H\rho_{oi}\dfrac{d\beta}{dp} + \left(\psi(\rho_o) - \dfrac{\gamma R}{\alpha(p)}\right)\rho_o n(p)}{1 + \dfrac{\mu_o}{\mu_g}\left(\psi(\rho_o) - \dfrac{\gamma R}{\alpha(p)}\right)}$$

(1) The data shown in steps 1 and 2 Eq 1 are used to evaluate the parts of this equation, since the pressure taken is again 1550 psi. The terms including H drop out since no gas cap exists.

(2) $R = S + \alpha(p)\psi(\rho_o)$
$R = 151 + 5690 \times 0.168$
$R = 1106$
$R = 1106 \times 5.62$ ft³/bbl
$= 6210$ ft³/bbl

Sample calculations are thus shown for determining the change in residual oil saturation during a 100 psi decline in reservoir pressure and the average gas-oil ratio during that decline, for primary recovery and pressure maintenance where r equals 0.6. To predict reservoir performance, this process is repeated for successive 100 psi decrements using the equation for the particular type of withdrawal contemplated at that pressure.

A Reservoir Study of the West Edmond Hunton Pool, Oklahoma

By Max Littlefield,* L. L. Gray,* Member, and A. C. Godbold,* Member AIME

(New York Meeting, March 1947)

Abstract

The West Edmond pool of Central Oklahoma, a limestone reservoir, has an area in excess of 29,000 acres and as of Sept. 15, 1946, had produced 53 million barrels of oil from 731 wells at an average depth of 6900 ft. Water has encroached into the reservoir along the west side of the pool and although the area of water invasion is large the net volume of water influx is small, because encroachment has been primarily into a fracture system.

The most significant part of this study concerns the character of the Hunton reservoir. Geological study of cores of the producing section was made to supplement core-analysis data. It was determined that approximately 90 pct of the pore volume was contained in intergranular or sand-like porosity and 10 pct in fractures (intermediate porosity). The porous limestone is divided into blocks by the fractures, although in the strongly dolomitic parts of the producing section, fractures are less well developed. The low-permeability intergranular porosity, largely subsidiary to the high-permeability fractures, will produce oil into the fractures by evolution of solution gas. The fractures in effect serve as drainage channels for production of oil from the intergranular porosity. Because of such a large difference in permeabilities of the two components, a high degree of by-passing will occur, and, accordingly, the economics involved in undertaking full-scale high pressure gas injection operations have been seriously questioned.

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Introduction

The West Edmond Hunton pool, which covers portions of Canadian, Logan, Oklahoma, and Kingfisher Counties in Central Oklahoma, is the largest reservoir producing oil from a limestone in the state. The total area of the pool comprises about 29,240 acres and development is considered to be essentially complete.

In all, 731 producing wells have been completed in the Hunton reservoir at an average depth of approximately 6900 ft, and have yielded a cumulative oil production in excess of 53 million barrels as of Sept. 15, 1946. In addition to wells completed in the Hunton limestone, 21 wells have been completed in the Bartlesville sand at a depth of approximately 6500 ft, which have produced a total of 730,000 bbl of oil. One small producer has been completed in the Cleveland sand at a depth of 5700 ft. However, a study of only the Hunton limestone reservoir will be presented in this paper.

The most significant phase of this study concerns the special type of geological core examination that was made in an effort to ascertain the type and degree of porosity in the rock in accordance with lithologic types. Results of this geological study showed the West Edmond pool to be of such a complex nature as to appreciably affect the behavior normally associated with homogeneous reservoirs. Recognition of this condition in the

reservoir essentially eliminates the prediction of performance histories by rigorous calculation, thus no predictions of gas-oil ratio and bottom-hole pressure behavior are made.

Development

The discovery well, which was drilled in the NW-NW-SW of sec. 32-14N-4W by Ace Gutowsky and other interests, had the Wilcox sand as an objective. Failing to find production in this sand at a depth of 7690 ft, the operator perforated the Bois d'Arc section of the Hunton limestone from 6938 to 6956 ft and obtained an initial production of 535 bbl of 41°API gravity oil per day through a 9/32-in. choke in April 1943.

Development in the field was rather slow at first when it was discovered that the entire Bois d'Arc section was cut out by an old stream channel less than a mile north of the discovery well. However, when good production from the Bois d'Arc section of the Hunton limestone was found north of the old stream channel, the development program gained momentum and reached a peak in February 1945, when 62 wells were completed during the month. As of Sept. 15, 1946, there were 731 Hunton wells completed in the pool with little prospect for much additional development.

The West Edmond pool is approximately 17 miles long and 5 miles wide at its widest part, which is through the northern half of the reservoir. The pool is only some 2 to 3 miles wide in the southern portion. An old stream channel, which passes through the middle of the pool in an east-west direction, completely segregates the Bois d'Arc section of the Hunton limestone into two parts. The pool is bounded on the east by the truncation of the upper part of the Hunton and on the north by a thinning of the section. A water table at approximately −5930 ft subsea limits the pool on the west, as well as on the south.

Geology

Many engineering problems that arise during the producing life of a reservoir are solved by application of knowledge concerning the characteristics of the reservoir rock. Perhaps the most important characteristic is porosity, and attempts are continually being made to obtain more data on the areal and vertical distribution of porosity in quantitative terms of degree and continuity. This geological discussion of the West Edmond field emphasizes the factor of porosity. The evidence bearing on the manner of development of porosity is discussed, but more attention is given to the evidence concerning the physical characteristics of the producing porosity as it now exists. The West Edmond pool, which is a stratigraphic trap, is on the flank of a large structure on the "Granite Ridge Trend." The axis of the "Ridge" passes through the older Edmond pool 5 miles east of the West Edmond pool and continues southward below Oklahoma City and northward into Nebraska. The major structures along this trend have the common characteristics of pre-Pennsylvanian uplift and erosion followed by differential uplift during the Pennsylvanian and westward tilting in post-Pennsylvanian time.

Fig 1 is a cross section of the field by McGee and Jenkins.[1] The Pennsylvanian lies across an erosional surface of Mississippian lime, Woodford shale, and Hunton lime in the limits of the West Edmond field. To the east the overlap continues to the Wilcox. The evidence of the extent and degree of pre-Pennsylvanian erosion has been shown by McGee and Jenkins. The maximum uplift was in the Oklahoma City field some 12 miles to the southeast. West Edmond is well down

[1] References are at the end of the paper.

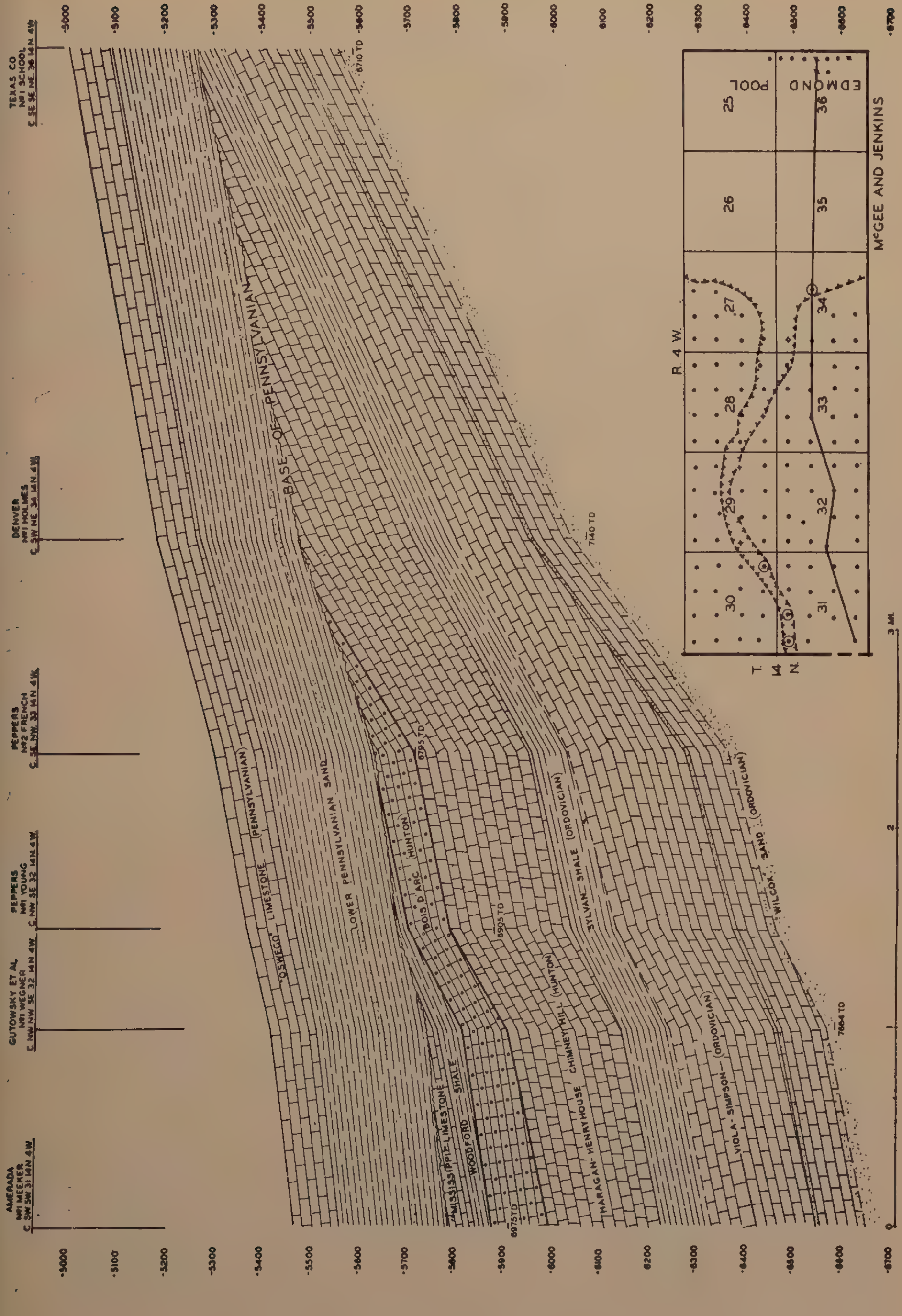


FIG 1—EAST-WEST CROSS SECTION, WEST EDMOND FIELD. (*McGee and Jenkins*.[1])

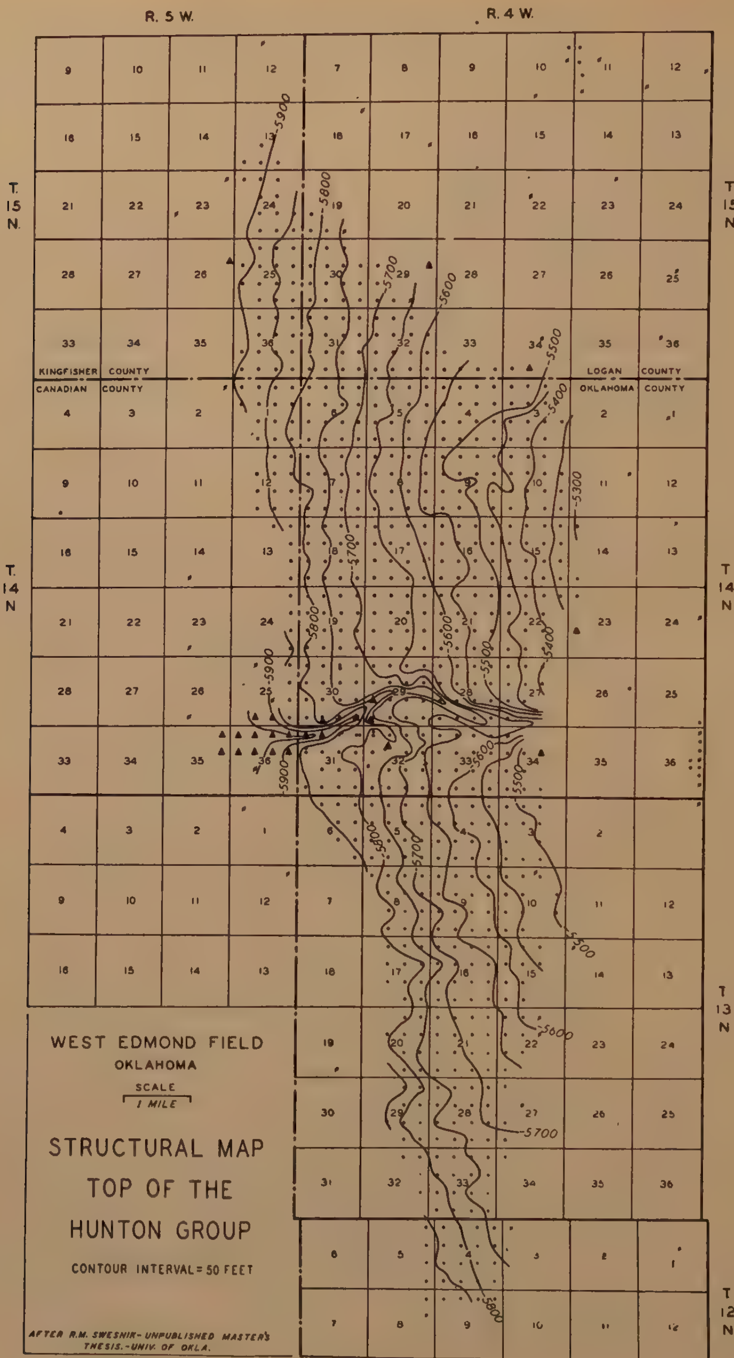

R. 5 W.
R. 4 W.
T. 15 N.
T. 14 N
T 13 N
T 12 N
KINGFISHER COUNTY
CANADIAN COUNTY
LOGAN COUNTY
OKLAHOMA COUNTY
WEST EDMOND FIELD
OKLAHOMA
SCALE
1 MILE
STRUCTURAL MAP
TOP OF THE
HUNTON GROUP
CONTOUR INTERVAL = 50 FEET
AFTER R.M. SWESNIK- UNPUBLISHED MASTER'S THESIS.-UNIV. OF OKLA.

FIG 2.

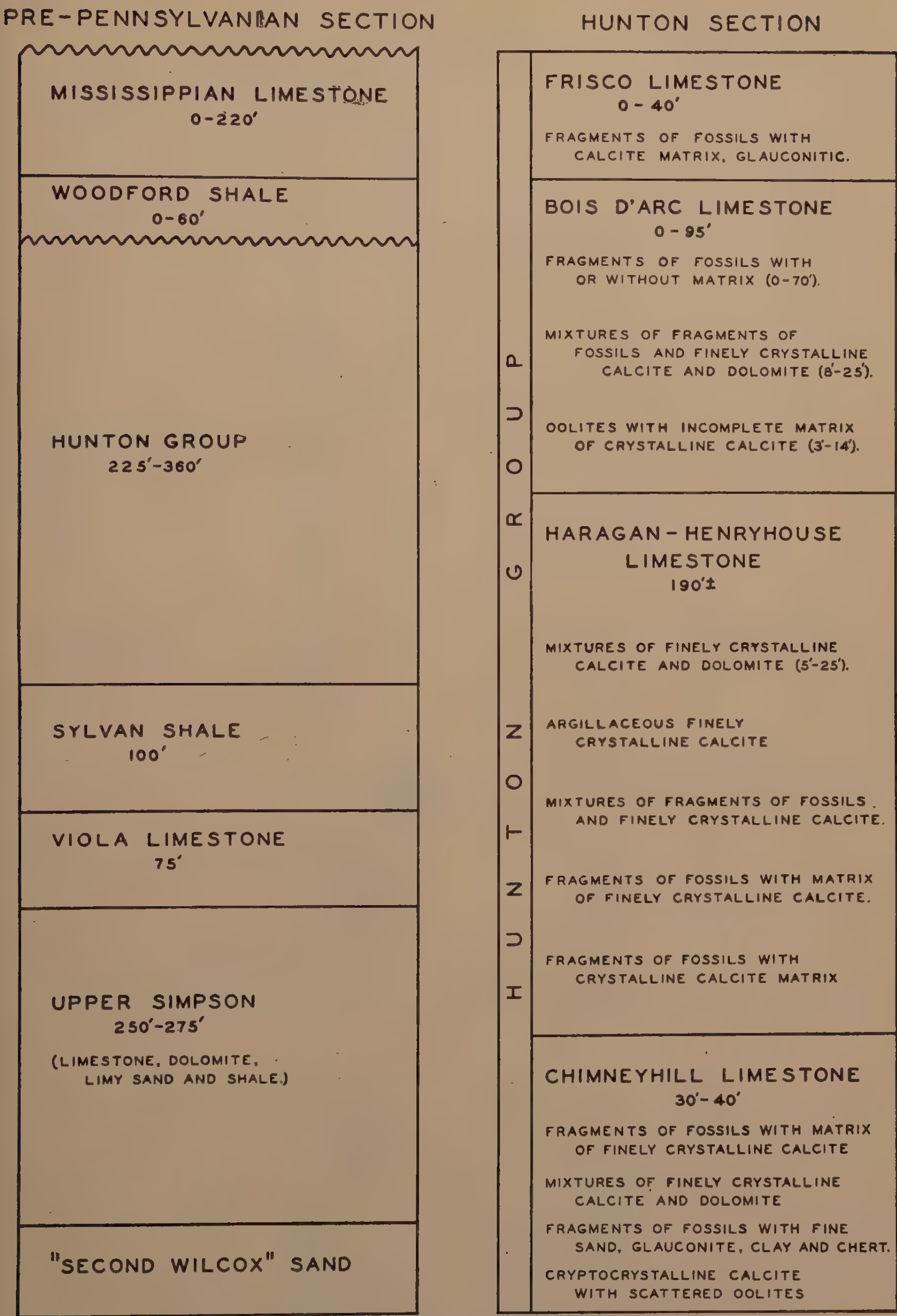


FIG 3—SECTIONS WEST EDMOND FIELD, OKLAHOMA.

the flank of the northward-plunging end of this uplift. The area can be assumed to have been topographically high during exposure with westward drainage, which crossed the outcrop of the Hunton.

An earlier erosional surface is that overlain by Woodford shale. This pre-Mississippian erosion surface shows some degree of truncation on the members of the Hunton with greater erosion to the

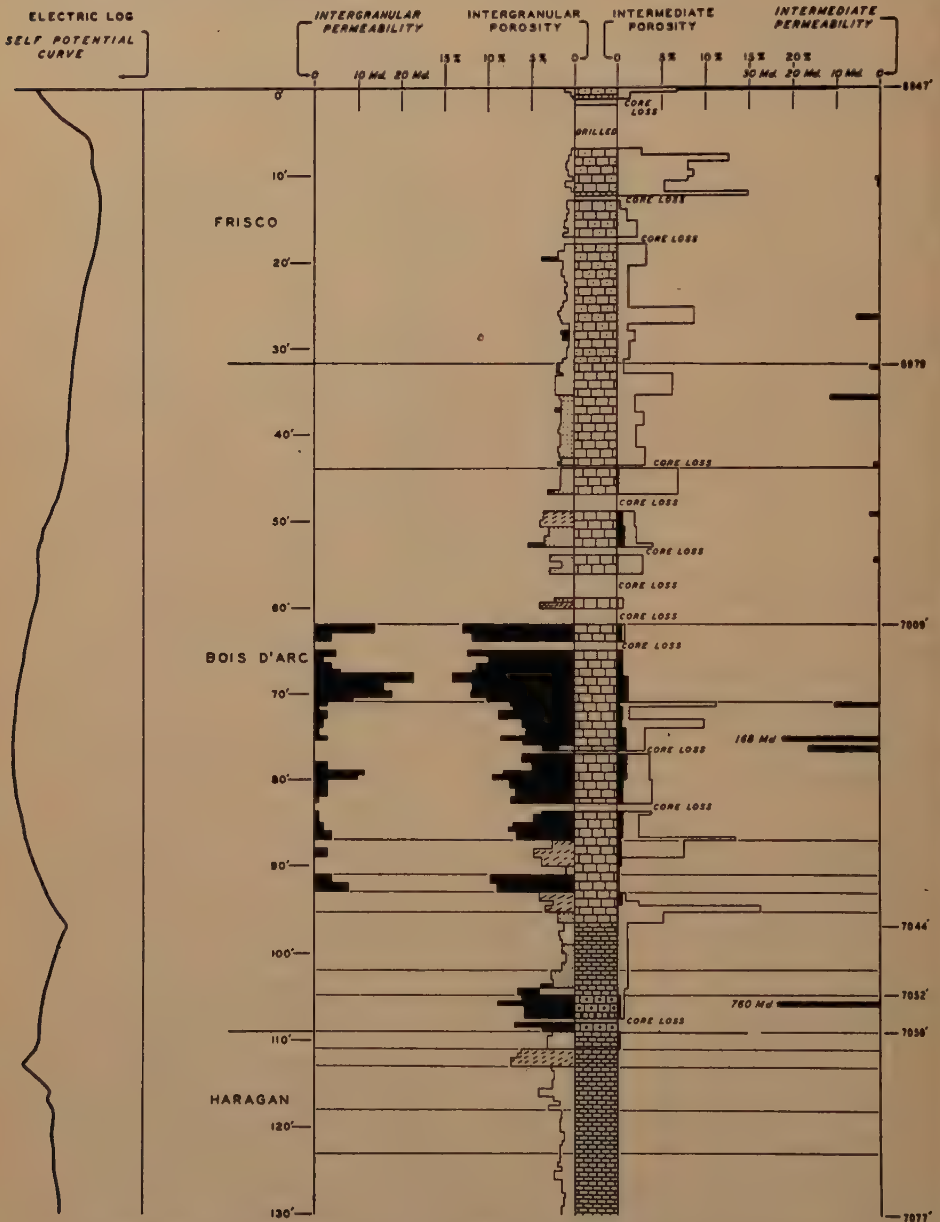


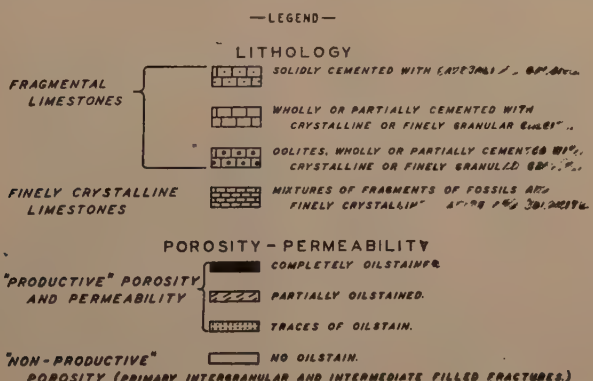
FIG 4—GULF NO. 1 STREETER, C-SE-SE SECTION 20-13N-4W, WEST EDMOND FIELD. (Legend on opposite page.)

north and northeast. The combined results of solution during these two periods of erosion are significant in the development of porosity in the Hunton limestone.

Fig 2 shows the structure of the field on the paleotopographic surface of the top of the Hunton group. The total closure between water level, at approximately −5930 ft, and the highest production is about 560 ft. The structure is a monocline. Northeast closure is the pre-Woodford edge of the Bois d'Arc and east closure is the pre-Pennsylvanian edge of the Bois d'Arc. The pool is separated into two parts by a narrow canyon-like valley of an old stream course. The maximum depth of this valley is 140 ft and the Bois d'Arc section is entirely eroded. The development of this channel by erosion furnished a topographically low outlet for ground water and thus facilitated movement of ground water down to the level of the drainage channel.

A graphic section of the West Edmond pool is illustrated in Fig 3. The pre-Pennsylvanian section is shown on the left side. Although the Hunton group is commonly spoken of as a unit, the "Hunton lime," it is made up of several limestone members, which have physical differences marked enough to affect the porosity. Basically the Hunton was originally made up of two types of component particles, fragments of fossils (4 to 1/20 mm) and finely crystalline calcite and dolomite (1/16 to 1/64 mm). With these were deposited slight admixtures of oölites, silt, clay, and glauconite. Some of the depositional mixtures of these component particles were modified, during consolidation, by the addition of clear crystalline calcite. The essential physical differences of the size of component particles, arrangement in space, and degree of cementation, are factors that affected the action of the subsequent porosity-making processes of solution, dolomitization, and fracturing.

Fig 4 is a detailed graphic log of Gulf-Streeter No. 1, showing both the intergranular and intermediate porosity. The entire Hunton group in this well was cored with a diamond bit with 97 pct recovery. This figure shows only the upper, or so-called Bois d'Arc, producing section. Production is also obtained from the lower Hunton, particularly in the northeastern part of the field. The porosity is divided into two types, intergranular and intermediate. Bulnes and Fitting[2] define intergranular rocks as "those in which the size, shape, and spatial distribution of the pores, and the way they are interconnected, are determined essentially by the number, the geometric properties and the distribution of the sedimentary units. In the intermediate type, in addition to the intergranular openings, cavities occur, whose size, shape, and position in the rock bear no direct



relationship to the number, to the geometric properties, or to the spatial distribution of the sedimentary units."

In rocks that are considered as intermediate porous media, but that also have an intergranular character, the terms intergranular and intermediate can be applied to the void space, as intergranular and intermediate porosity. Although mathematical treatment alone serves to point out the broader characteristics of porosity, it is also necessary to give detailed attention to the rocks themselves. Observations, microscopic or otherwise, should be stated in terms of physical properties, preferably in quantitative terms, rather than in the qualitative descriptive manner that geologists require for the purposes of identification and correlation. Statement in quantitative terms requires close attention to the actual specimens used in laboratory tests of porosity and permeability. Such attention usually suggests the making of additional tests to isolate and evaluate individual factors that affect porosity and permeability. Moreover, it is necessary to evaluate critically the limitations of laboratory tests in the determination of true porosity and permeability and to give similar critical attention to the problems involved in obtaining and selecting representative samples.

On the left of the graphic log in Fig 4 are data on intergranular porosity and permeability. Both porosity and permeability represent laboratory determinations. The solid black represents complete oil stain, the diagonals represent partial oil stain, the dotted areas show traces of stain, and the porosity lacking oil stain is shown in outline only. In the West Edmond reservoir, oil stain is present in only a part of the intergranular porosity shown by laboratory determinations. Permeabilities below one millidarcy were not determined. All plugs with permeabilities of one millidarcy or more were in oil-stained rock, so permeabilities are also shown in solid black. On the right side of the graph are data on intermediate porosity and permeability. The porosity data are based on measurement of fractures in 3-in. cores. The percentages of seams and fractures that are nonporous by reason of filling with clay, calcite, pyrite, or dolomitic lime are shown by the outline alone. Those which are open and oil stained are shown as solid black percentages. The permeabilities shown are laboratory measurements of observable seams in the test plugs. Obviously, only the smaller seams can be retained intact in a test plug. These permeabilities are not considered to be representative of the permeability in the 3-in. core and have little meaning in relation to the reservoir as a whole.

The Frisco member of the Hunton group, illustrated in Fig 5, is a limestone made up of fragments of fossils cemented with calcite. The laboratory tests show from 0.5 to 2.0 pct porosity. The voids are mainly hollow fossils or isolated interfragment interstices, which were not completely filled. The intergranular permeability is negligible and the intergranular porosity, from a producing standpoint, is also negligible, as only that associated with the surface of the test plug is measured.

The intermediate porosity consists of two types of fractures. One type is of irregular, vertically oriented voids filled with clay and silt. The continuity, the irregular walls that show local evidence of solution, and the fact that the filling is similar to the insoluble residue of the limestone, are evidence that these are solution-enlarged fractures. Although there is now no appreciable void space, these filled fractures afford clues to the original magnitude and distribution of the solution channels. The other type of fracture also tends to be vertical, has matching walls, and cuts across the solution-enlarged

fractures. The clayey filling of the solution-enlarged fractures was compressed when fractured, which is strong evidence that the later fracturing occurred after a section accounts for virtually all of the oil-stained intergranular porosity. Rock areas showing as much as 3 pct primary porosity show no evidence of solution and

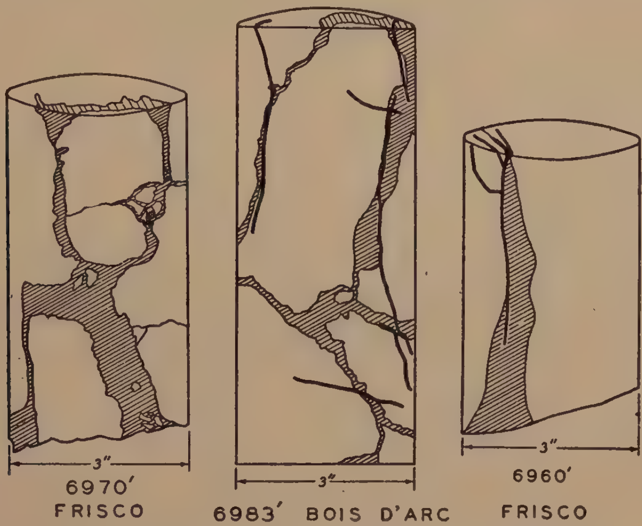


FIG 5—FRACTURES IN FRISCO AND BOIS D'ARC LIMESTONES.
Gulf No. 1 Streeter, Section 20-13N-4W. Heavy lines are late fractures that cut earlier residuum-filled solution-enlarged fractures.

considerable load of sediment had accumulated above the Hunton. The continuity of the late fractures within a 3-in. core was shown by forcing colored liquid paraffin into the core through a hole drilled through the vertical axis of the core. After cooling, the core was sawed longitudinally to intersect the fractures that were filled with paraffin.

Referring again to the cored section of Streeter No. 1, Fig 4, the greater part of the Bois d'Arc is made up of fragments of fossils with several degrees of interstitial filling. The upper part is calcite-cemented and is similar to the overlying Frisco. In the middle part are individual layers, which were incompletely cemented. Some layers have fine interstitial fragments of fossils, some have finely crystalline calcite, and some may have had little or no interstitial filling.

Solution in the fragmental Bois d'Arc no oil staining. Evidence as to the degree of solution can be seen adjacent to the solution-enlarged fractures. The process started by the opening of the seams along the contacts between component particles or along contacts between component particles and the cement. In some cases partial solution of the matrix was accompanied by differential solution of some of the fragments of fossils. Frequently there is difficulty in determining the degree of primary interstitial porosity, because such porosity is commonly affected by solution. Solution progressed through complete removal of interstitial material and partial removal of component particles. In advanced stages of solution the porosity in some instances was decreased as removal of lime at contact points permitted compaction. About 15 pct intergranular porosity appears to be the upper limit in solution riddled fragmental limestones.

Figs 5 and 6 illustrate the fracture porosity in the fragmental Bois d'Arc section. The courses of solution-enlarged fractures in the partially cemented fragmental limes range from single fractures to ramified rifts in the less competent zones of high primary porosity. Solution, instead of concentrating on the walls of the fracture, tended to disseminate through the rock and encompass the limits of the core. In some cases the ramified rifts are seen only when preserved by filling, the present porosity being greater outside the rift than within. Late fractures intersect both solution-enlarged fractures and solution porosity.

The factors controlling the second set of fractures, even in zones in which the earlier solution-enlarged fractures are open, are believed to have been late structural movement, compression due to 6000 ft of overburden and changes in competence due to solution.

Table 1 shows the relationships of intergranular porosity and permeability to details of lithology. Fragmental limes tend to develop permeability as porosity increases. Finely crystalline rocks develop permeability as the dolomite content increases. The sum of solution porosity and primary porosity (Table 1) does not always equal the average laboratory test porosity because the laboratory data include fracture porosity. The values estimated for primary porosity may in some cases be low, such as the 5 pct shown for dolomite, but all of this porosity is considered to be nonproductive.

The Streeter No. 1 core has no highly dolomitic rocks in the section shown in Fig 4. Fractures are less abundant in the finely crystalline rocks. Solution-enlarged, filled fractures are present but open fractures are not common and in some cases appear to be partially sealed by recrystallization. The northeast part of the

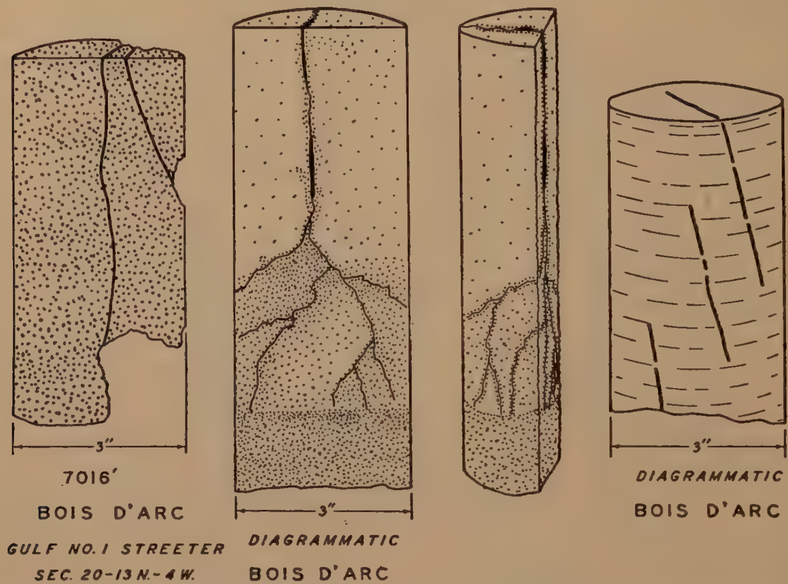


FIG 6—POROSITY IN BOIS D'ARC LIMESTONES.
Heavy lines show fractures in Bois D'Arc limestones containing intergranular porosity. Specimen at right is finely crystalline limey dolomite.

field, where dolomitic rocks are present in greater proportion than in the central and southern part, probably has a less continuous fracture system. Late fractures calcite. Solution has affected both the matrix and the oölites, and frequently secondary dense argillaceous dolomitic material fills a part of the intergranular

TABLE 1—*Intergranular Porosity and Permeability of Lithologic Types*

Material	Condition		Footage of Core, Ft	Number of Test Plugs	Average Lab. Test Porosity, Pct	Estimated Primary Porosity, Pct	Estimated Solution Porosity, Pct	Estimated Intergranular Permeability Based on Lab. Tests, Md
Fragmental lime, with calcite cement	Little solution		41.7	62	1.93	1.42	0.36	0.06
Fragmental lime with partial cement either crystalline or granular calcite	Little solution		49.7	59	2.54	1.73	0.62	0
	Considerable solution		81.25	114	7.84	0.09	7.62	6.74
Mixtures of fragments of fossils and granular calcite and dolomite	Predominantly fragmental	Matrix mainly calcite	21.45	37	2.42	2.42	0	0
		Matrix mainly dolomite	8.2	10	7.35	5.00	2.35	0.98
	Predominantly granular	Groundmass mainly calcite	22.0	29	4.03	3.81	0.22	0.03
		Groundmass mainly dolomite	21.55	33	14.18	5.00	9.18	8.20
Oölitic fragmental lime	Considerable solution		34.05	57	11.05	0	11.05	1.38
Groundmass of granular calcite and dolomite with scattered fragments of fossils	Groundmass mainly calcite. Little oilstain		36.6	46	6.77	6.77	0	0
	Groundmass calcite and dolomite. Diss. oilstain		34.2	60	8.62	5.00	3.62	0.14
	Groundmass mainly dolomite. Strong oilstain		28.7	38	16.67	5.00	11.67	0.73

are present and show no mineralization. Some of the finely crystalline calcitic rocks show late fractures, which have no oil stain. These fractures can be followed downward into lines of weakness, which will split when tapped with a hammer. Such unstained fractures are considered to have occurred along lines of weakness during drilling. Other lines of weakness can be discovered by hammer blows. Virtually all limestones tend to fracture more selectively in some one direction perpendicular to the bedding planes.

The oölitic limestone is a fragmental lime with a complete or partial matrix of crystalline calcite or finely crystalline solution porosity. Both solution-enlarged fractures and late open fractures cut the oölitic lime.

In the north central part of the field the Woodford shale lies directly on the lower part of the Bois d'Arc fragmental lime and some 60 to 90 ft of the section present at Streeter No. 1 is missing. The finely crystalline limes between the fragmental member and the oölitic member are thicker and more dolomitic. The beds below the oölitic limestone are also strongly dolomitic. As compared with Streeter No. 1, the bulk of the porosity is in finely crystalline beds. Fractures are present in all beds but in general the volume of

the fractures is less in the finely crystalline beds. In the north and northeast portions of the pool the amount of dolomitization tends to increase and to extend downward in the section. Because dolomite beds do not appear to retain fractures it is probable that the degree and extent of fracturing is less in that area. However, evidence from cuttings suggests vugular voids, which may introduce another type of intermediate porosity.

Values of intergranular porosity and intermediate porosity for eight cored wells are shown in Fig 7. In wells from which core recoveries were less complete, cores of 2 to 3-ft intervals enabled the bracketing of core losses into lithologic and porosity types. Quantitative figures obtained from laboratory tests of subjacent and superjacent rocks were used. This procedure is believed to be conservative, as it is probable that losses were greater in rocks of higher porosity. In determining intergranular porosity, units of similar lithology that have similar types, or similar degrees of the same type of porosity, are averaged, both for over-all porosity from laboratory analysis and for oil-stained or "producing" porosity. The permeabilities shown are laboratory figures from fracture-free plugs.

Intergranular porosity is variable in distribution and degree. The Frisco shows a zone of intergranular porosity in Anna Paul No. 2. The fragmental member of the Bois d'Arc shows porous zones in all wells. The finely crystalline beds between the fragmental and oölitic members show relatively low oil-stained porosities. This is due to higher primary porosity and less fracturing. The oölitic limestone shows consistently high porosity. The beds below the oölitic have relatively high primary porosity and considerable oil stain. The self-potential of the electric log shows a minor bulge opposite the lowest producing porosity, regardless of the porosity type or stratigraphic position. The vertical distribution of porosity is far from uniform.

The intermediate porosity values indicate the average of open-fracture porosities. Estimates of widths of fractures were based on evidence seen in the complete cores of Streeter No. 1 and are considered to be conservative. As representative intermediate permeability figures are impossible to obtain by laboratory methods, the indicated permeabilities shown represent estimates of well to well permeability based on the number and degree of fractures. The maximum range is shown as 0 to 1000 md, which implies connecting, rather than continuous, fractures from well to well.

Table 2 shows a recapitulation of the over-all averages of intergranular and intermediate porosities for the Frisco, Bois d'Arc, and Haragan. The capacity of the Frisco is clearly limited but fractures make up about 20 pct of the total porosity. In the Bois d'Arc there is considerable variation in average porosity between wells. The averages show intermediate porosity to be slightly less than 10 pct of total porosity. In the Haragan (below the oölitic member) both intermediate and intergranular porosities are variable. It is probable that some fractures, partially sealed by recrystallization, may be included in the intergranular porosity. These may be permeability channels of limited extent but are not true intermediate porosity. The footage of total void space is also highly variable from well to well because of differences in both average porosity per foot of pay and total pay thickness.

In summary, it has been found from geological examination of the cores secured in the West Edmond pool that porosity is of two general classifications; namely, intergranular and intermediate or fracture porosity. Void space contained in the fracture system has been approximated to be on the order of 10 pct of the total

TABLE 2—*Summary of Porosity and Permeability Data from Hunton Cores of Eight Wells, West Edmond Field, Oklahoma*

Well	Average Percentage of Porosity By Formations									Total Interval of Pay Zone from Cores	Average "Producing" Porosity, Pct	Footage of Total Void Space		
	Frisco			Bois d'Arc			Haragan-Henryhouse							
	Feet	Intermediate Porosity, Pct	Intergranular Porosity, Pct	Feet	Intermediate Porosity, Pct	Intergranular Porosity, Pct	Feet	Intermediate Porosity, Pct	Intergranular Porosity, Pct			Intermediate Void Space	Intergranular Void Space	Total Void Space
Gulf Streeter No. 1, 20-13N-4W	32	0.07	0.03	77	0.46	3.63	2	0.4	0	111	2.88	0.3832	2.8112	3.1944
Gulf Flynn No. 1, 21-13N-4W	26	0.01	0	66½	0.60	3.72	2	0.05	0	94½	3.04	0.4051	2.4723	2.8774
Gulf Anna Paul No. 2, 8-13N-4W	35	0.18	0.88	78½	0.70	6.73	4½	0	6.75	118	5.43	0.6128	5.7956	6.4084
Gulf Messenbaugh No. 2, 20-14N-4W				45½	0.90	3.81	10½	0.06	0.42	56	3.93	0.4193	1.7820	2.2013
Gulf Wright No. 1, 17-14N-4W				42	0.77	6.54	20	0.29	6.16	62	6.99	0.3798	3.9555	4,3353
Gulf Wright No. 3, 17-14N-4W				38½	0.55	7.90	18	0.03	4.24	56½	7.11	0.2165	3.8041	4.0206
Gulf Christner No. 1, 7-14N-4W				34?	0.33	6.43	20	0	9.91	54	7.94	0.1190	4.1672	4.2862
Sohio Lynch No. 4, 18-14N-4W				40	0.16	3.76	15	0.02	4.63	55	4.05	0.0839	2.1341	2.2280
Average per foot		0.09	0.34		0.57	5.20		0.09	5.45			(0.43 %)	(4.44 %)	(4.87 %)
Average per well		0.03	0.11		0.56	5.33		0.11	4.01	75.9	5.17	0.3275	3.3653	3.6928

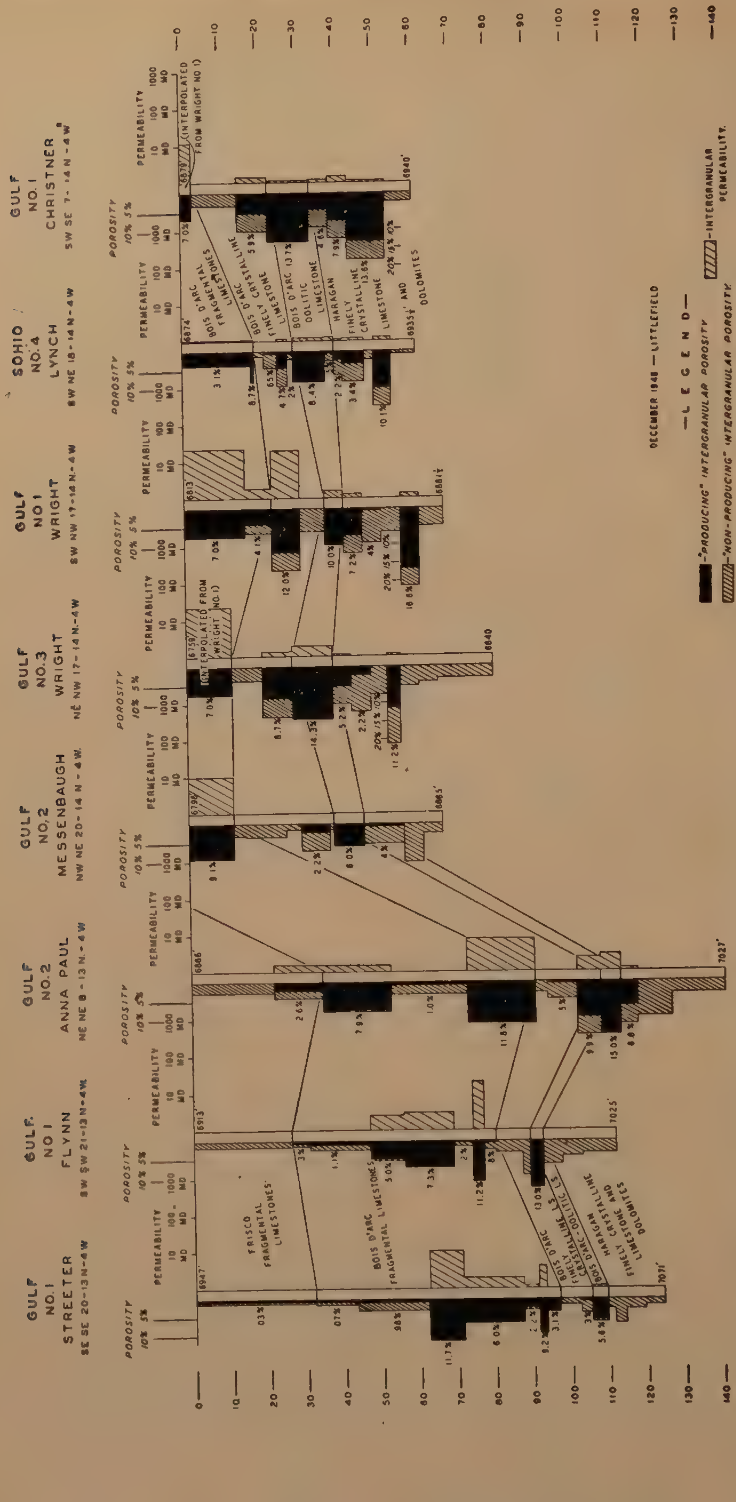


FIG 7a—INTERGRANULAR POROSITY AND PERMEABILITY OF PRODUCING SECTION OF HUNTON IN EIGHT CORED WELLS, WEST EDMOND FIELD.

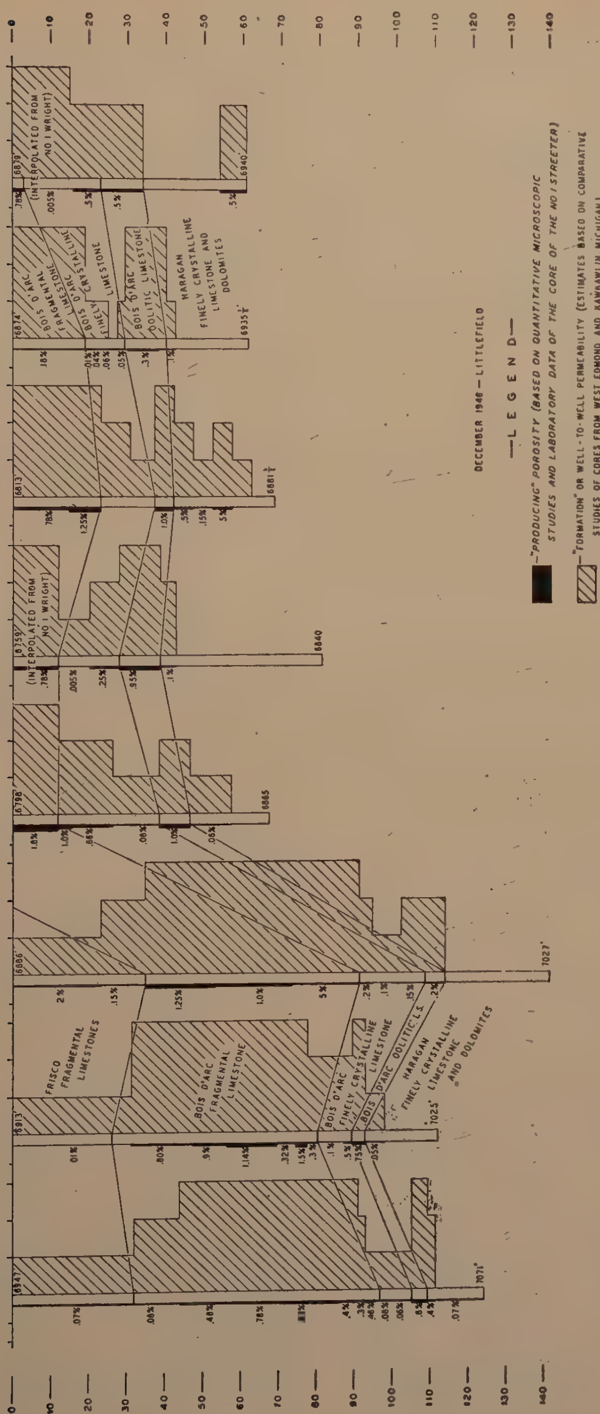


FIG 7b—INTERMEDIATE POROSITY AND PERMEABILITY OF PRODUCING SECTION OF HUNTON IN EIGHT CORED WELLS, WEST EDMOND FIELD.

void space; thus most of the oil is contained in the intergranular or tight porosity. Permeabilities may also be classified as to intergranular and intermediate. The fracture system is characterized by high permeabilities, whereas the intergranular system is characterized by low permeabilities. Accordingly, the West Edmond reservoir is a complex interrelated system of reservoirs, the fracture system having extremely good communication and the remainder having practically no intercommunication.

State Regulations

As provided by regulations of the Oklahoma Corporation Commission, the pool was developed on 40-acre spacing with wells located at or near the center of each 40-acre tract. The only exception to this pattern was the discovery well, which was located on 10-acre spacing in a 40-acre unit.

State regulations regarding casing programs and completion methods required that at least 300 ft of surface casing be set and cemented to the surface. The original rules provided that the oil string be set on bottom and cemented to at least 2800 ft above the casing shoe; however, the rules were changed in December 1943, to allow the casing to be set not higher than the top of the producing formation and cemented to a point not less than 2700 ft above the casing shoe. It is required that all production be through tubing not to exceed 2½ in. and set not higher than the top of the casing perforation. Special applications for larger tubing have been granted for some of the pumping wells, which produce water.

The pool is prorated on an individual well basis and no well is given an allowable in excess of its ability to produce. The allowable for the first well completed in the pool was set at 400 bbl per day, but upon completion of the second well the top allowable was reduced to 300 bbl per day. The maximum gas-oil ratio permitted without penalty was 2000 cu ft per barrel. In May 1944 the top daily allowable was reduced to 200 bbl per well with the same penalty attached to any well with a gas-oil ratio exceeding 2000 cu ft per barrel. The adjusted allowable of a well penalized for high gas-oil ratio is determined by multiplying the normal allowable of such well by 2000, divided by the actual gas-oil ratio for that well. In December 1944 the daily well allowable was reduced to 150 bbl with the same gas-oil ratio penalty applied. In December 1945 a pool allowable of 80,000 bbl per day was established, which was distributed among the active wells in the pool. From December 1945 to September 1946 the pool allowable has varied from 70,000 to 80,000 bbl per day and on Sept. 1, 1946, the pool allowable was reduced to 40,000 bbl per day. The top well allowable during September 1946 was 64 bbl per day. Beginning Jan. 1, 1946, the gas-oil ratio allowable without penalty was established on the basis of the arithmetical average gas-oil ratio of all wells tested plus the amount of gas remaining in solution in the reservoir oil at that time. Gas-oil ratio and bottom-hole pressure surveys are now taken semiannually and the present allowable gas-oil ratio without penalty is 7203 cu ft per barrel, based on the August 1946 surveys.

Method of Completion

All wells in the pool were drilled and completed with rotary tools and only two strings of casing were used. Generally 10¾-in. surface pipe was run and, in accordance with State regulations, the pipe was cemented to the surface. Common practice was to use 7-in. casing for the oil string, which was set on bottom and cemented with 700 to 1000 sacks. Some operators preferred to perforate the entire pay section, whereas others perforated selectively in accordance with electrical

log and geological data. After the State regulations were revised in December 1943, a number of wells were completed with the oil string on top of the Hunton sure was 3145 psia. At original conditions the residual oil shrinkage was determined to be 48 pct and the oil viscosity at saturation pressure was 0.58 centipoises. The

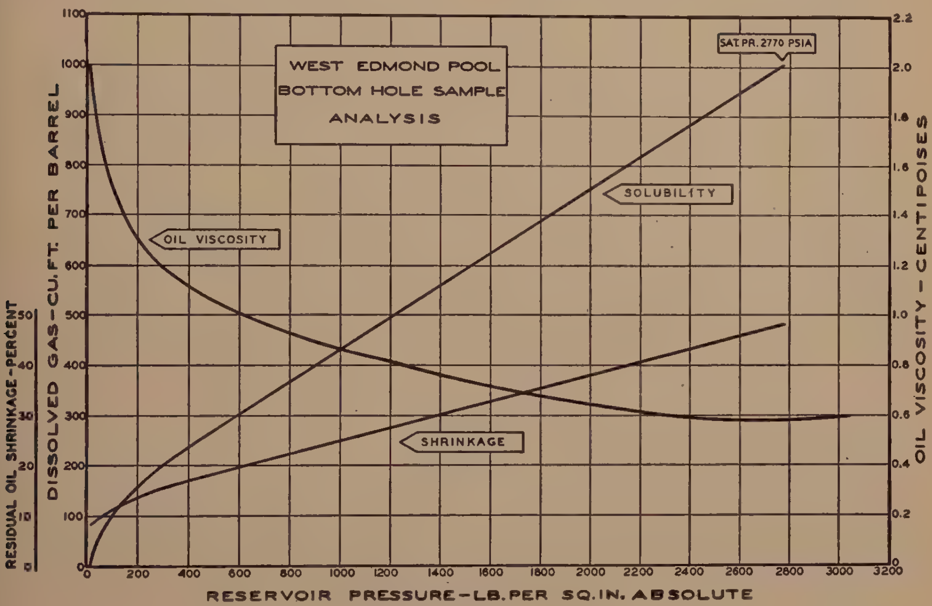


Fig 8.

formation. Practically all wells were acidized with 1000 to 1500 gal of acid and natural flow was obtained in nearly all completions. All wells are produced through 2-in. or 2½-in. tubing with the exception of a few pumping wells for which exceptions to the State rules were made and 3-in. tubing was allowed.

Reservoir Fluid

A number of bottom-hole samples were obtained at pressures approximating 3000 psia, and analyzed for solubility, viscosity, and shrinkage. As shown on Fig 8, the average saturation pressure was determined initially to be 2770 psia, and the volume of gas originally dissolved in the oil was 1010 cu ft per barrel. The reservoir had no free gas cap initially and the reservoir oil was slightly undersaturated, since the initial reservoir pressure

oil viscosity at atmospheric pressure was 2 centipoises.

From analyses of Hunton water samples, the formation water has a specific gravity of 1.129 and a total solids content of 187,500 milligrams per liter.

Performance of Reservoir

In Table 3, statistics on reservoir performance, such as average static bottom-hole pressure, cumulative oil, gas, and water production, cumulative pressure drop, cumulative oil produced per cumulative pressure drop, average gas-oil ratio, and cumulative gas-oil ratio, are presented for 11 periods in the history of the reservoir. These data, along with other pertinent information such as number of wells and daily oil and water production rates, are shown graphically on Figs 11, 12, and 13. As of Sept. 15, 1946, produc-

tion had been 53,178,000 bbl of stock-tank oil, 122.5 billion cu ft of gas, and 5,220,000 bbl of water. During this period of production the reservoir had undergone a pressure decline of 1243 psi, which amounts to an average of 42,700 bbl of oil production per pounds per square inch drop in pressure. The August 1946 weighted average gas-oil ratio extrapolated to Sept. 15, 1946 indicated 5600 cu ft per barrel, and the cumulative gas-oil ratio was 2305 cu ft per barrel.

TABLE 3—*Reservoir Performance Data, West Edmond Pool*

Survey Date	Static Bhp, Psia	Cumulative Oil Prod., 1000 Bbl	Pres. Drop, Psi	Cumulative Pres. Drop, Psi	Cum. Bbl per Cum. Psi Drop, 1000 Bbl	Average Gas-oil Ratio, Cu Ft per Bbl	Cumulative Gas Prod., MMcf	Cumulative Gas-oil Ratio, Cu Ft per Bbl	Cumulative Water Prod., 1000 Bbl
Orig.—Apr 43	3,145	0	0	0	0	1,010	0	1,010	0
Mar 15, 1944	2,984	1,040	161	161	6.5	1,010	1,050	1,010	2
May 15, 1944	2,916	1,760	68	229	7.7	1,010	1,780	1,010	5
Aug 15, 1944	2,814	3,190	102	331	9.7	1,010	3,370	1,010	36
Nov 15, 1944	2,796	6,100	18	349	17.5	1,007	6,160	1,010	103
Feb 15, 1945	2,719	10,480	77	426	24.6	1,283	11,410	1,090	225
May 15, 1945	2,616	16,260	103	529	30.8	1,485	18,710	1,150	418
Sept 15, 1945	2,483	26,190	133	662	39.5	1,950	34,610	1,320	975
Dec 15, 1945	2,380	33,120	103	765	43.9	2,400	49,500	1,495	1,578
Mar 15, 1946	2,235	40,390	145	910	44.4	3,100	69,800	1,730	2,486
Sept 15, 1946	1,902	53,178	333	1,243	42.7	5,600	122,500	2,305	5,220

The original bottom-hole pressure in the Hunton reservoir was 3145 psia. The first general pressure survey made in March 1944 on 19 wells showed an average pressure of 2984 psia at a subsea datum of −5864 ft. Since March 1944 periodic pressure surveys have been made at intervals of 3 to 6 months on approximately 25 pct of the wells in the field, generally the same wells being tested on each survey. The last survey was made in September 1946, at which time the average bottom-hole pressure was 1902 psia for the 180 wells tested. Pressures have declined continually throughout the producing history of the pool. Fig 9 is an isobaric map constructed on the last general pressure survey of September 1946.

The first general gas-oil ratio survey made between Oct 14 and Nov 15, 1944, showed an average gas-oil ratio for the 199 wells tested of 1007 cu ft per barrel of oil. This average gas-oil ratio is nearly the same as the original solution ratio of 1010 cu ft per barrel. Gas-oil ratios have increased with each quarterly survey and by Sept. 15, 1945, the average ratio was 1950 cu ft per barrel, with approximately 35 pct of the wells tested having a ratio in excess of 2000 cu ft per barrel. The last gas-oil ratio survey was completed in August 1946, at which time 713 wells were tested and found to have a weighted average gas-oil ratio of 5180 cu ft per barrel. Of the wells tested, 583, or 81.8 pct, had a ratio in excess of 2000 cu ft per barrel, and 184 wells, or 25.8 pct of those tested, had a ratio in excess of 7203 cu ft per barrel, which is the present maximum gas-oil ratio allowed without penalty.

The first water production was reported on Jan. 31, 1944, in the Schmitz-Specht No. 1-B, SE NE sec. 36-14N-5W, and 7 months later 10 wells were producing water with a cumulative water production of 36,497 bbl. By March 1, 1945, the number of water-producing wells along the west side of the pool had increased to 42, with a cumulative water production of 247,504 bbl. On April 1, 1946, 132 wells were producing water with a cumulative water production of 2,677,228 bbl, and as of Sept. 15, 1946, there were 157 wells

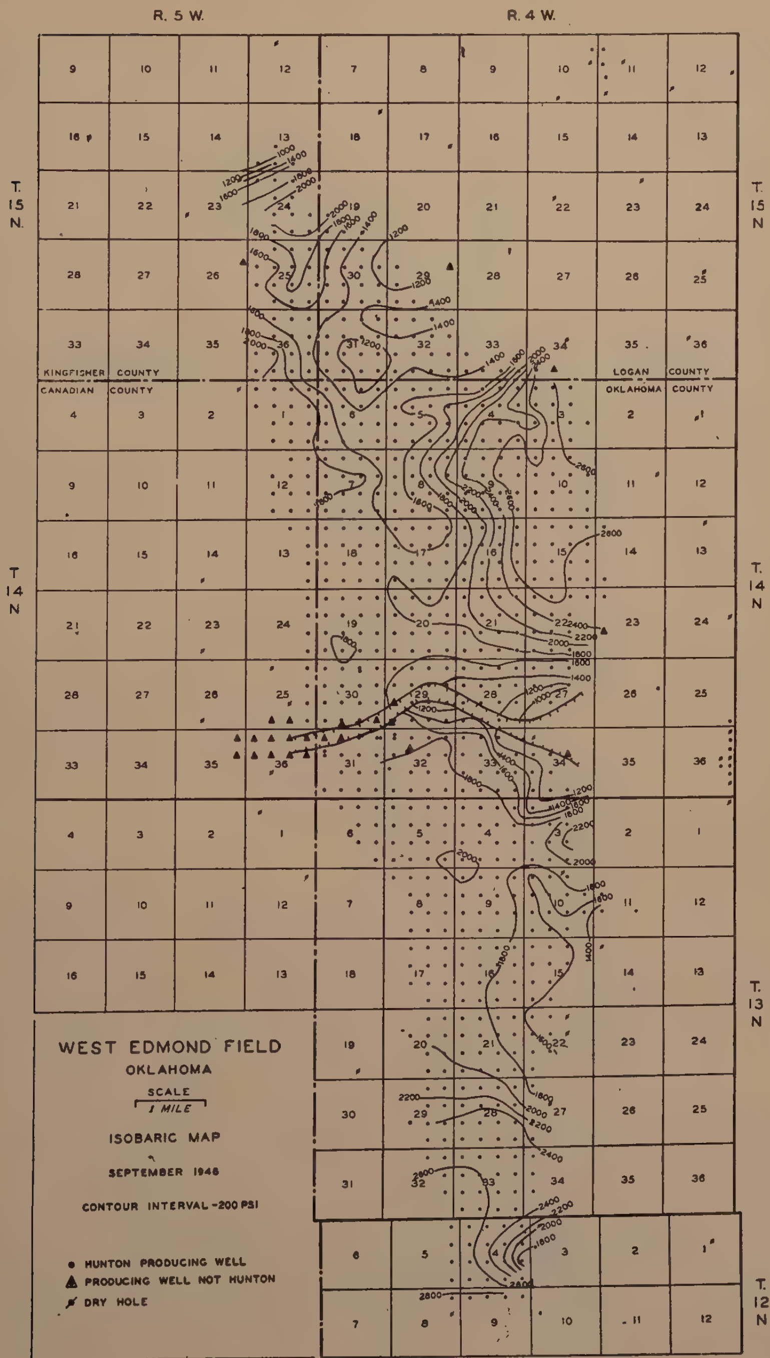

R. 5 W.
R. 4 W.
T. 15 N.
T. 14 N
T. 13 N
T. 12 N
KINGFISHER COUNTY
CANADIAN COUNTY
LOGAN COUNTY
OKLAHOMA COUNTY
WEST EDMOND FIELD
OKLAHOMA
SCALE
1 MILE
ISOBARIC MAP
SEPTEMBER 1946
CONTOUR INTERVAL -200 PSI
HUNTON PRODUCING WELL
PRODUCING WELL NOT HUNTON
DRY HOLE

Fig 9.

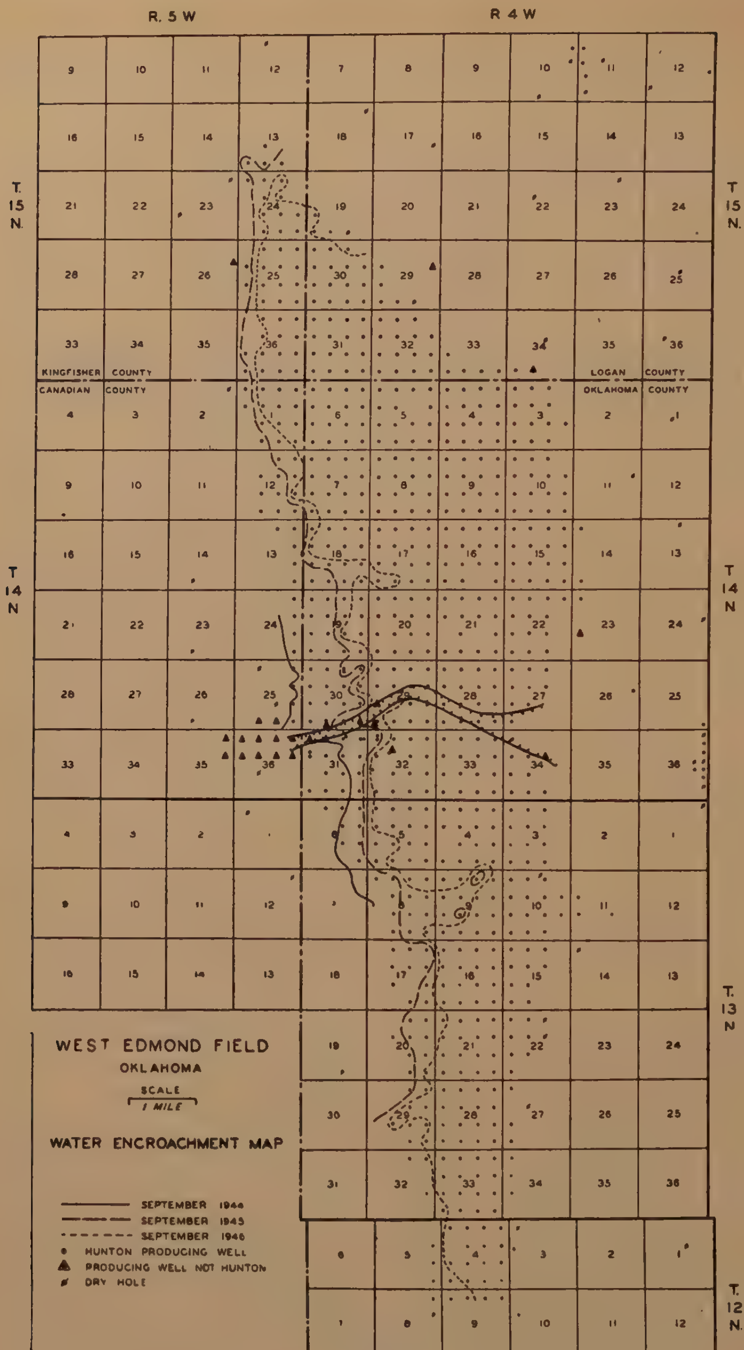

R. 5 W
R 4 W
T. 15 N.
T 14 N
T. 13 N
T. 12 N.
KINGFISHER COUNTY
CANADIAN COUNTY
LOGAN COUNTY
OKLAHOMA COUNTY
WEST EDMOND FIELD
OKLAHOMA
SCALE
1 MILE
WATER ENCROACHMENT MAP
SEPTEMBER 1944
SEPTEMBER 1945
SEPTEMBER 1946
HUNTON PRODUCING WELL
PRODUCING WELL NOT HUNTON
DRY HOLE

FIG 10.

producing 15,500 bbl of water daily, with a cumulative water production of 5,220,000 bbl. Fifteen wells that formerly had produced water are now reported to be dropped 30 psi from a static condition. The results of this series of tests show that communication does exist in the reservoir and it is interpreted that communication

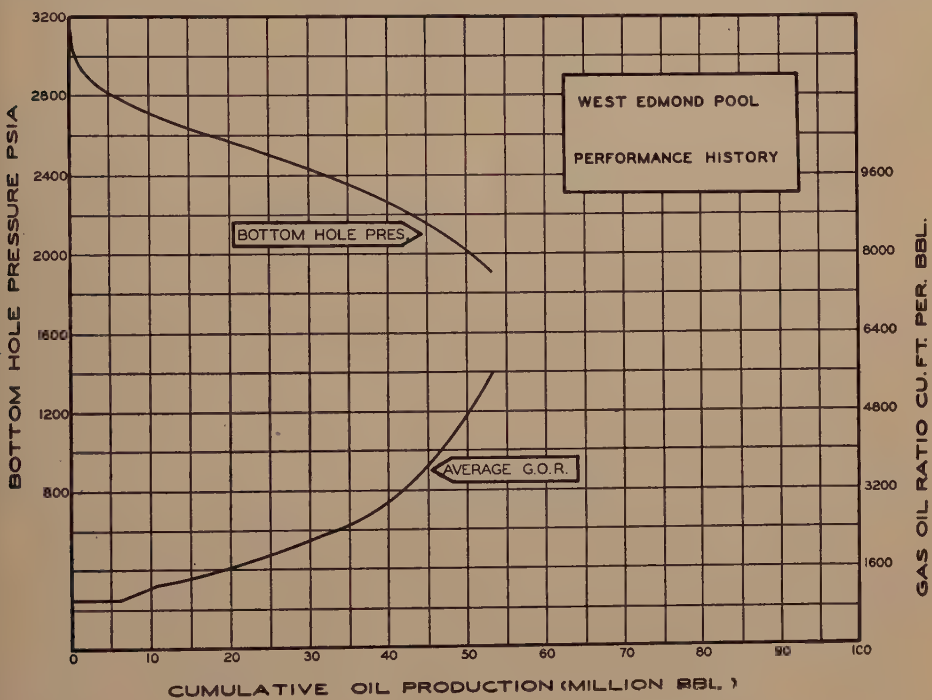


FIG 11.

producing clean oil. A water-encroachment map, Fig 10, shows the chronological history of the advancing water front by yearly intervals. At the present time 71 wells in the pool are equipped to pump, most of which are producing water. However, a number of these wells flow at least a portion of their production.

A series of interference tests was made on three offsetting wells in secs. 7 and 18-14N-4W to determine what effect the operation of two wells would have on an offsetting well. The three wells selected for study had productivity indexes of 2.8, 5.0, and 45.0. It was found that when the two higher capacity wells were produced at rates of 800 to 1100 bbl per day, the bottom-hole pressure in the third well is through fractures rather than the low-permeability intergranular porosity. Bottom-hole-pressure build-up tests secured on a large number of wells in the pool indicate, in general, a rather rapid stabilization of bottom-hole pressure.

Interpretation of Data

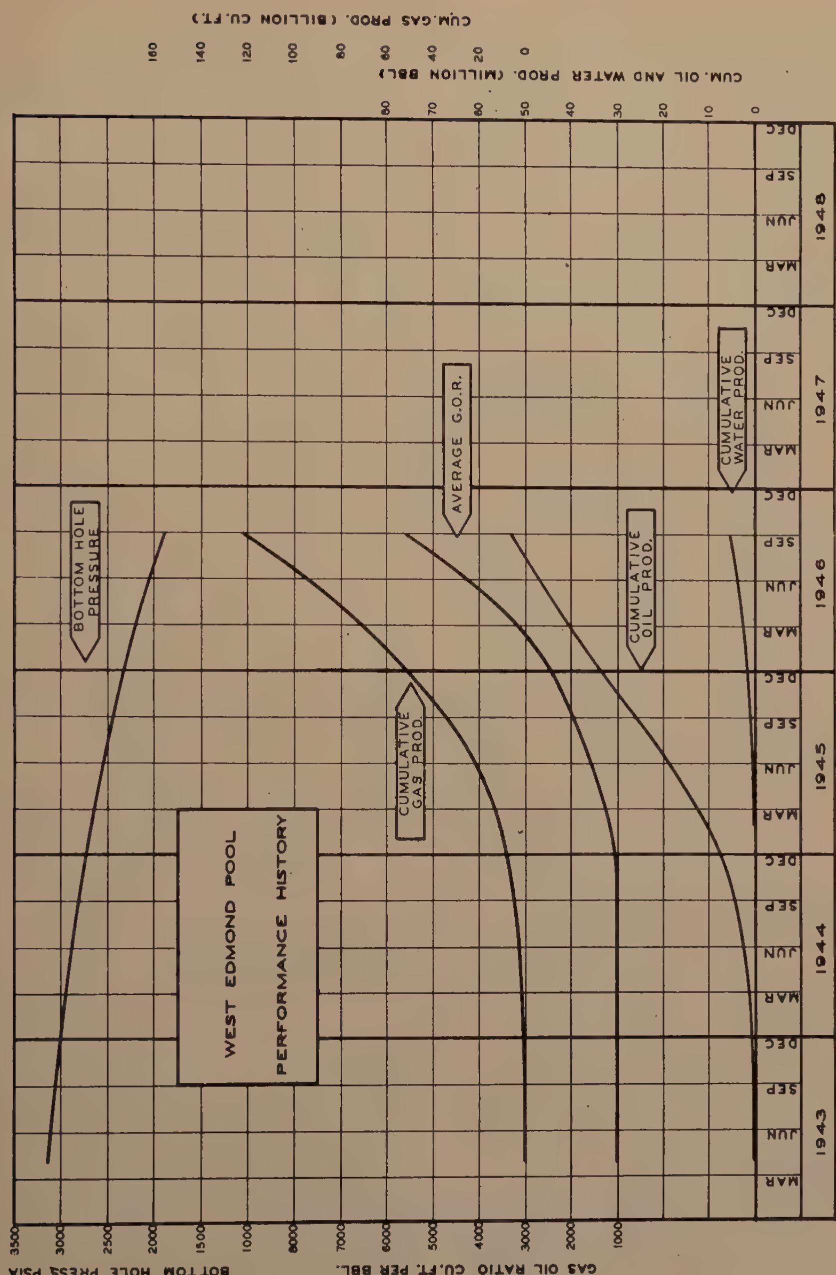
As evidenced by the data presented in the geological section of this paper, the geology of the West Edmond pool is somewhat unique, at least for pools in this area. Many significant interpretations of performance are based directly upon this geological study. The study showed that the pool contained two general classes of porosity; namely, intergranular and

fracture porosity. Moreover, it was determined that the fracture pore volume was on the order of 10 pct and the intergranular pore volume on the order of 90 pct of the total pore volume. Geological interpretations are that the high-permeability fracture system substantially isolates the very low-permeability intergranular system. The fractures, in effect, serve as drainage channels for production of oil from the intergranular porosity. If no fractures had existed in the Hunton reservoir, well capacities would have been small, probably less than 300 bbl per day. Since well capacities are relatively large, it is interpreted that the fracture system is the greatest contributing factor to well potentials. Because it is very difficult to measure fracture permeabilities in the laboratory, the laboratory data alone may be very misleading. Such a condition cannot be blamed on "core loss." As the fracture system is three dimensional, it is interpreted that very good communication exists throughout the various producing sections in the fracture system. Moreover, from the geological information supplied it must be interpreted that a very small degree of communication can exist within the intergranular system, except as this system communicates directly with the fractures.

Although there has been some discussion among operators in the West Edmond pool as to whether or not the Hunton reservoir initially contained saturated oil, the evidence from a considerable number of bottom-hole samples indicates an original saturation pressure of 2770 psia, as compared with a bottom-hole pressure of about 3000 psia at the time of sampling and a pressure of 3145 psia at original conditions. Accordingly, it is interpreted that the pool was producing in the early stages as a result of expansion of the liquids in the reservoir plus some water encroachment. At the present time the reservoir is producing oil primarily by the solution gas-drive type of mechanism. There has been some water encroachment into the reservoir along the west side of the pool, which has made some contribution toward retarding the pressure decline.

Present indications are that total water influx into the reservoir is on the order of 20 to 25 million barrels, including water already produced. There are in excess of 6000 acres that actually produce water and more than 10,000 acres from the pool boundary into which water has encroached. Net oil-saturated pore volume in this area is calculated to be on the order of 200 million barrels. Accordingly, the *net* volume of water intrusion estimated for the pool (20 to 25 million less 5,220,000 bbl produced) is less than 10 pct of the oil-saturated pore volume within the area of water encroachment. The fact that the total area of water encroachment and the pore volume within that area is quite large, as compared with the volume of water intrusion, indicates that water entered the reservoir through permeable streaks (fractures), thus by-passing the majority of the intergranular void space. From geological concepts of the characteristics of the Hunton reservoir, this type of performance should be anticipated. A relatively limited water encroachment is indicated and it is predicted that pressures will continue to decline.

Because of the relatively small volume of the fracture system, as compared with the pore volume of the intergranular system, the most efficient recovery can be realized only if the field is produced in such a manner as to obtain maximum recovery from the intergranular porosity. It appears that the only process by which the intergranular porosity will produce oil is by the evolution of gas from solution and subsequent expansion. Further, it appears that the only means of utilizing the energy within the intergranular system is by creating a differential pressure



WEST EDMOND POOL
PERFORMANCE HISTORY
BOTTOM HOLE PRESSURE
AVERAGE G.O.R.
CUMULATIVE GAS PROD.
CUMULATIVE OIL PROD.
CUMULATIVE WATER PROD.
CUM. GAS PROD. (BILLION CU. FT.)
CUM. OIL AND WATER PROD. (MILLION BBL)
BOTTOM HOLE PRESS PSIA
GAS OIL RATIO CU. FT. PER BBL.
1943
1944
1945
1946
1947
1948

Fig 12.

between the fracture system and the intergranular system. Oil will be produced from the intergranular system into the fracture system, which affords essentially the only means of communication to the well bore. Since gas injected into the reservoir would essentially fill only the high-permeability fracture system, by-passing the majority of the oil in the low-permeability intergranular system, it is believed that such gas injection would not materially contribute to the production of additional profitable oil from the reservoir. At the present time gas-oil ratios are 5.6 times the initial solution ratio. This very rapid growth of the gas-oil ratio, with a corresponding relatively small percentage produced of ultimate oil recovery, is interpreted to mean that reservoir performance is being predominated by performance of the fracture system at this stage. Certainly, if the reservoir were acting as one homogeneous body, gas-oil ratios would have been substantially less at this period in the life, because this type of performance would indicate a rather limited reservoir and small ultimate recovery when other data point to a much larger pool and greater recovery.

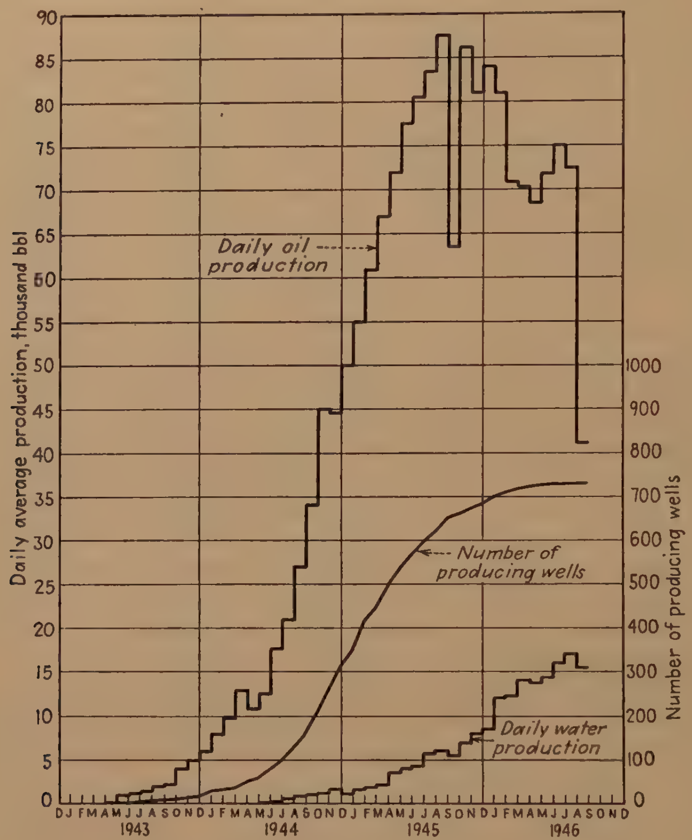


Fig 13.

It is predicted that in most cases wells that produce water will also continue to produce oil for a considerable period of time. Such oil production will be due to

the bleeding of the intergranular porosity into the fracture system as the pressure continues to decline. Oil will be produced from the fractures along with water, although in many cases water-oil ratios will be quite high.

From volumetric calculations it is estimated that approximately 600 million barrels of stock-tank oil was originally in place in the West Edmond pool, and that fractures contained about 60 million barrels of this total. It should be anticipated that the percentage of oil recovery from the fracture system will be high because the fractures serve as good channels for gravity drainage. On the other hand, it is anticipated that the percentage of oil recovery from the intergranular porosity will be relatively small. Estimating that 70 pct will be recovered from the fractures, and that the intergranular recovery will be limited by a final free gas saturation of 32 pct at 200-psi reservoir depletion pressure in the intergranular porosity, the ultimate recovery for the West Edmond pool is estimated to be on the order of 165 million barrels by primary methods of operation.[3] Although some economic benefit could probably be realized by unitized operation of the reservoir, permitting selective well production, it is not believed that the injection of gas into a reservoir such as this could materially increase the ultimate recovery. With such a wide difference between permeabilities of the fracture system and the intergranular system, and assuming good communication throughout the fracture system, it seems logical that gas injected into the reservoir would be recycled through the fractures at considerable expense without contributing much toward additional oil recovery. It is believed that this condition will prevail regardless of the amount of oil that ultimately may be produced from the reservoir. Therefore, the production of the estimated 165 million barrels of oil is not essential to the conclusions reached regarding the value of gas injection. Near the end of the producing life of the pool at a time when oil production from the intergranular porosity has become small and pressure in the fracture system is low, it is believed that it would be economically feasible to sweep the remaining oil out of the fractures by a gas-injection program. Such a program would require only a very small outlay of investment as compared with an expenditure necessary for gas injection at much higher pressures.

Acknowledgments

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DISCUSSION

L. E. Elkins*—The authors of this paper have made an excellent study of the lithological and physical characteristics of the reservoir rock in the West Edmond Hunton limestone pool. Their qualitative interpretation of the types of porosities and permeabilities that exist in the reservoir are believed to be well founded;

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however, there is considerable difference of opinion among engineers and geologists as to the quantitative interpretation of the porosity, permeability and extent of the so-called fracture system. The writers have laid particular emphasis on the occurrence of fractures in the reservoir rock, and point out that approximately 10 pct of the total porosity exists in the fracture system. It is my opinion that fractures occur, but the evidence supporting a connected fracture system throughout the field is far outweighed by other evidence to the contrary.

1. The bottom-hole pressure map of the West Edmond field, as shown in Fig 9, indicates a variation of bottom-hole pressure of approximately 1800 psi and a variation between wells located 1320 ft apart by as much as 600 lb. It is not believed that such a pressure condition could exist with any type of connected fracture system.

2. The productivity indexes of wells in the field vary considerably from less than one to more than 50. This also indicates the lack of a field-wide fracture system but confirms the presence of both intermediate and intergranular porosity.

3. There is approximately 600 ft of structural closure in the field, and if continuous fracturing existed to any substantial degree, gas segregation would occur in the upper part of the reservoir. While some high gas ratios are found upstructure there are just as many high ratio areas in other parts of the field.

4. The writers have concluded that the limestone in West Edmond is divided into something in the order of 6-in. cubes on the basis of a few scattered cores, each of which represents only a hole of 3-in. diameter cut in the center of a 40-acre tract. While fracturing is noted in some of the cores, the composite summary of all available evidence does not support blocks of intergranular dolomite of this dimension.

Granting that complications are introduced by the geometry of the so-called blocks of intergranular limestone as related to more permeable channels surrounding these blocks, there are, in my mind at least, three factors that have not been given the consideration due when drawing conclusions that gas injection, for example, would probably be of no value in such a reservoir. These factors are as follows:

1. Every block of intergranular limestone as described in the paper will, in itself, operate as a single reservoir and will be subjected to depletion, both as to degree and rate, depending upon the geometry of the particular block as well as the fluid and pressure conditions within the block and in the permeable channels adjacent to and surrounding such block.

The fluid characteristics and the pressure gradients set up between the center of the block and the outside dimensions of block to which oil will move may vary considerably within each of these literally millions of blocks. Two important factors controlling the rate and ultimate depletion of each block are the effective permeability to oil within the block, and the pressure differential employed from within the center of the block to adjacent relatively permeable channels. It is obvious that a pressure differential has to exist in order for this flow to take place. There is one school of thought that would create maximum pressure differentials at all times. This, on the face of it, might indicate that depletion from each of these blocks might proceed at a relatively higher rate. On the other hand there might be some optimum pressure differential. For example, if pressures at the outer dimensions of each block are at some intermediate value the effective permeability to oil at the boundary of each of these blocks may be substantially higher than it would be if the pressures in the permeable channels surrounding the blocks are kept reduced to an absolute minimum. In this respect, it may be possible that oil would move out faster with some intermediate pressure differential than could be possible at absolute minimum differentials and absolute maximum differentials.

Petroleum technology at this time has not proved either by research or by field performance just where, in range of pressure differentials, this optimum might be. Thus, we have no proof whether or not pressures should be sustained at intermediate positions or permitted to decline relatively fast in order to most successfully deplete the type of reservoir described in this paper.

2. One other important factor is with respect to supplying the energy required to ultimately deplete the relatively permeable channels of the oil that will "seep" out of the tight intergranular limestone into those per-

meable channels. It is recognized that the return of all gas to a field such as West Edmond might not be desirable, depending upon the storage capacity of the permeable channels and depending upon the rate of oil seepage into those permeable channels under the conditions imposed upon the reservoir. Nevertheless, long after the major source of gas energy has been depleted, and after the more permeable channels have been exhausted of their normally recoverable oil, there will be oil seeping into these channels along with the solution gas that comes with it out of intergranular limestone. The permeability to oil in the more permeable channels will be relatively low because of early depletion, and the solution gas itself probably will not be adequate to move that oil to well bores at existing low pressure differentials at such rates that wells can be operated economically. At that time the cycling of gas through those channels would result probably in a substantial increase in ultimate recovery from the reservoir by: (1) maintenance of economic producing rates, (2) keeping the permeable channels stripped to a minimum degree of the oil that continually will seep into that channel until the reservoir approaches its ultimate equilibrium. Here it is difficult to anticipate early in the life of a field just how much gas should be stored in the reservoir in order to save this reserve of gas for recycling in the final stages of depletion. Too much gas stored will impose a terrific load on gas-handling facilities; too little gas stored will lead to a sacrifice in ultimate oil recovery.

There has been some comment on the fact that not much gas can be stored in the permeable channels in a pool like that described in this paper. From the standpoint of storing free gas, that is correct; but engineers should bear in mind that a large portion of the gas normally produced as free gas with decline in pressure can be stored as gas in solution by maintaining pressure at relatively higher levels. In other words, storage of gas by gas injection is accomplished both by maintaining higher pressures in the gas phase of the reservoir and by keeping gas in solution until a later stage of depletion where pressures would be permitted to decline to relatively low levels, and this gas can then become available as free gas and used as such for energy within the reservoir.

Here again, because of the complex nature of the geometry of a reservoir such as West Edmond, not only the reservoir as a whole but each local area in the field must be evaluated with respect to the factors mentioned above. This evaluation can be made best by actually attempting to conserve gas by shutting in the high-gas-oil ratio wells and by injecting some gas, endeavoring to keep conditions in each area in such a manner that the maximum gas can be saved for ultimate depletion purposes without imposing an undue load on gas-handling facilities that might economically be justified in the operating program of the field.

3. Another important factor that cannot be overlooked in a reservoir such as exists at West Edmond is related to the amount of water encroachment into the field, which is a function of the reservoir pressure maintained in the field. If the author's picture of the nature and distribution of the porosity is at all correct, it is a foregone conclusion that when edge water moves clear through the reservoir oil is bound to be trapped in the intergranular spaces. At least this oil is trapped to the degree that its removal by handling of water production is probably limited by economic considerations. Therefore, an optimum condition exists somewhere between two extremes—maintenance of relatively high pressures with a parallel necessity of handling relatively large volumes of gas as contrasted with allowing pressure to decline rather sharply and permitting a substantial influx of water from the surrounding aquifer.

Operators should not overlook the possibility of using two-stage or possibly three-stage separation in a field such as West Edmond, whereby gas might be taken from producing wells at pressures of 500 lb or greater, and returned directly to the reservoir at relatively low expense. Gas coming off the low-pressure separators and from relatively low-ratio wells could be used to keep the normal gasoline plant loaded with relatively rich gas without requiring them to compress large volumes of gas from near atmospheric pressure to field pressure for injection purposes.

JACK TARNER*—The first part of the paper presented consists of a lithologic study of the

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Hunton formation, with a quantitative evaluation of the fractures present in cores. The second part of the paper is an engineering study presenting "many significant interpretations based directly upon this geologic study."

The authors have concluded, by "assuming good communication throughout the fracture system," that gas injected into the reservoir would be recycled through the fractures at considerable expense without contributing much toward additional oil recovery. This is a very important conclusion, which has for its foundation an *assumed* condition as to the persistence of fractures between all wells. This pool has been producing for almost four years. Well and pool performance data show that fractures do not communicate between wells.

Fractures found in cores have often been formed in the coring process. In the reservoir, subjected to approximately 10,000 lb of overburden pressure, seams can be insignificant and only become appreciable in size when that pressure is removed. Large fractures are shown in the core specimen in Fig 5 of this paper, but these fractures have been filled by secondary deposition. The later fracture system, which cuts the older system, and which appears in the specimen in Fig 6, is limited in vertical extent. The fractures terminate vertically in the small core specimen shown. When this condition is considered along with the statement "virtually all limestones tend to fracture more selectively in some one direction perpendicular to the bedding planes," it seems unreasonable to assume that they will connect some 1320 ft between wells.

The fractures present in the specimen in Fig 6 appear to carry through the massive, dense limestone and terminate as they enter the more porous limestone. It seems quite fortunate that this condition exists. The fractures could act as passageways for the injected gas to move through the dense limestone areas to the porous limestone, which is expected to yield the increased oil recovery resulting from unitized gas-injection operations.

It is not necessary to speculate as to the persistence of fractures found in cores when actual pool and well-performance data are available. Actual field performance has indicated that the fractures are not continuous between all wells. The pressure map shown in Fig 9 uses a contour interval of 200 psi. It is apparent that 200 psi difference in pressure exists between many offset wells and that differences of 1000 psi occur over distances of approximately one mile. These pressure differences could not exist in any completely fractured reservoir.

The same condition applies to producing gas-oil ratios. Many local areas of high gas-oil ratios have been formed. Under present producing conditions, this gas is only slowly migrating to the structurally high positions in the reservoir. Many offsetting wells are producing with gas-oil ratios that differ by 10,000 cu ft per barrel. If the reservoir were extremely fractured, migration of gas to the structurally high part of the reservoir would be rapid and offset wells would be producing with almost equal gas-oil ratios.

Pressure "build-ups" in the various wells have indicated large differences in formation conditions. Of 13 wells tested, three have had pressure "build-up" to static in less than 10 hr, the remaining 10 wells had pressure increases of from 100 to 430 lb during the second 24 hr of "shut-in" time. Two wells on which pressures were measured for four days had pressure increases of 100 and 200 lb the fourth day. These wells do not indicate any extreme fracture condition in the reservoir.

Productivity index tests do not indicate all wells to be fractured. Early in the producing life of this pool productivity index tests were made in 34 wells. Their indexes were divided as shown in Table 4.

TABLE 4—*Division of Productivity Indexes*

Productivity Index	Per Cent	Cumulative
Less than 0.5	11	11
0.5–1.0	24	35
1.0–1.5	26	61
1.5–2.0	11	72
2.0–3.0	10	82
3.0–4.0	4	86
4.0–5.0	3	89
Over 5.0	11	100

Approximately three fourths the number of wells tested had productivity indexes of less than 2.0, and only 11 pct were over 5.0. The indicated productivity index for the field is only 2.1. The thick producing sections in these wells would need only 10 to 20 md

permeability to have this productivity index. Only a relatively few wells have indexes indicative of even a small amount of fracturing.

Remedial work in the field has proved that the fractures do not extend vertically to join zones of high permeability. In one instance selective acidizing of the lower of two perforated intervals resulted in a decrease in the producing water-oil ratio. In another well, it was possible to isolate production from two different intervals by using a tubing packer. These results could not have been obtained in any completely fractured reservoir.

The authors conclude that "some economic benefit could probably be realized by unitized operation of the reservoir permitting selective well production." Selective production is employed in order to produce only the wells that have low producing gas-oil ratios. The high-gas-oil ratio wells are "shut in," and the gas that normally they would produce is made to travel through the reservoir to areas capable of yielding oil with low gas-oil ratios. An increased oil recovery is thus obtained. If this reservoir is of a nature that will permit the natural energy in the reservoir gas to be directed toward an increased oil recovery, those same high-gas-oil ratio wells could be converted to gas-injection wells and the injected gas could be directed through the reservoir in much the same manner to bring about an even greater increase in ultimate recovery.

L. F. Elkins*—This paper has presented a very interesting discussion of the fractured condition of the West Edmond Hunton limestone and has indicated the limitations this condition places on oil recovery by means of an external displacing fluid. I should like to make some comments about material-balance estimate of water encroachment, which the authors presumably used in comparing reservoir performance with geologic analysis of cores, and also about the inferences this water encroachment has in terms of gas-storage volumes and gas-oil ratios accompanying gas injection.

The authors used an initial saturation pressure of 2770 psia, average of a number of subsurface samples, but indicated that some operators believed the oil to be initially gas-saturated based on high initial gas-oil ratios of some upstructure wells. Since 514 ft of oil-filled closure exists between extreme top of known oil reservoir and the (−) 5864-ft pressure datum, actual pressure in vicinity of a possible initial gas cap was about 2990 psia. This is the highest saturation-pressure theory requires for equilibrium between oil and free gas. Two early subsurface samples from high P.I. wells had saturation pressures of 2902 and 2952 psia, respectively, and had very good checks between laboratory and field determined gas-oil ratios. Further proof of high saturation pressure is early pressure-production performance. Production by March 15, 1944, had averaged 6500 bbl per psi pressure drop with all measured top of pay pressures in excess of 2885 psia. Dividing by expansibility of undersaturated oil would indicate an initial oil content of 450 million barrels, an apparent good check between a very early material-balance estimate and later volumetric estimate of 600 million barrels. The only catch is that measured pressures were necessarily confined to the small developed area comprising only about 15 pct of the finally developed area. That and subsequent pressure surveys showed undeveloped area to have much higher pressure. Thus the 450-million-barrel figure must be multiplied by a factor of maybe as much as 4 or 5, which no longer is in agreement with volumetric data. Consideration of this and later data indicates that water influx was probably too small to account for production in excess of liquid oil expansion. This leaves only gas expansion as it is released from solution in oil as an explanation. These various factors all indicate a saturation pressure in excess of 2900 psia and probably as high as 2950 psia. More than likely some of the low-saturation-pressure samples had been exposed to large pressure drawdown in wells.

In addition to saturation pressure, the distribution of actual formation pressure must also be considered in material-balance calculations. To my knowledge this latter feature has never been discussed in literature on material-balance principles. It can be of considerable importance when large differences in actual formation pressure exist because of unequal unit fluid withdrawals or large

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structural relief. The Schilthuis form of material-balance equation for a reservoir containing no initial free gas is:

Expansion = Production − Water Encroachment

$$n(u - u_0) = \Delta n[u + (r - r_0)v] - (Z - z)$$

n	$(u - u_0)$	Δn	u	$(r - r_0)$	v	$(Z - z)$
Initial oil content	Unit expansion oil plus initial solution gas	Cumulative oil production	Unit volume oil plus initial solution gas	Cumulative net free gas-oil ratio	Formation volume factor of gas	Net water influx.

The usual procedure is to insert the factors $(u - u_0)$, u, and v corresponding to average datum pressure and solve for the initial oil content, or, in this case, net water influx. Since these factors are nonlinear with pressure, however, proper average values cannot correspond to average pressures. Until cumulative free gas production measured at reservoir conditions predominates over oil production, the balance is most sensitive to $(u - u_0)$. Thus weighting $(u - u_0)$ rather than pressures should give a more reliable result.

Values of $(u - u_0)$ calculated from mid-pay pressures for each well for the March 15, 1946, survey and 2950 psia saturation pressure were multiplied by the corresponding pay thicknesses to determine weighted average value of $(u - u_0)$. Values of u and v for pressure corresponding to the average value of $(u - u_0)$ were used to complete the calculation. The maximum initial oil content calculable, assuming no water influx, is 540 million barrels. Corresponding initial oil content using weighted average mid-pay pressure in the material-balance equation is 635 million barrels, and using weighted average datum pressure, the usual procedure, oil content is 690 million barrels. Approximately the same percentage divergences, 19 and 28 pct, respectively, occur assuming any likely quantity of water encroachment; and the calculated initial oil content is, of course, correspondingly reduced. Regional migration of fluids in the reservoir introduces error, since it is implicitly assumed in this method of calculation that the proper values of $(u - u_0)$ can be determined from pressures alone. Since, in general, fluids migrate from high to low pressures, error is toward the high side. This causes even more divergence from the "average" pressure method.

Since water has encroached over a considerable part of the reservoir, it can only be concluded that initial oil content was less than 600 million barrels, that considerably more gas has been produced than reported, or that well pressures are not representative of reservoir pressures. Fifty per cent more cumulative gas production, or reservoir pressures about 200 psi in excess of well pressures, or some combination of the two, is necessary for a 600-million-barrel initial oil content and a reasonable amount of water influx.

Material-balance calculations are thus of little value in calculating water influx, but fortunately in this case one other method can be used. In the past few months water production has leveled off at about 15,000 bbl per day, and many wells previously making small amounts of water now have water-free production. Thus current water influx is probably of the order of 15,000 bbl per day. It may have been slightly higher during the period of very high fluid-withdrawal rates just prior to the allowable reduction in September 1946, but probably has not averaged more than 15,000 bbl per day during the 3½-year producing life prior to Jan. 1, 1947. Probably not over 19 million barrels of water has thus encroached into the oil reservoir, 7 of which have been produced, leaving about 12 million barrels spread over an area of at least 7400 acres, since some 185 wells have produced water. This is an average of 1600 bbl per acre, or only 5 to 6 pct of the initial oil-filled reservoir in the invaded area. Ninety-four per cent of the water production for December 1946 was concentrated in 108 wells, making over 25 pct water. Assuming bulk of encroached water to be concentrated in 4300-acre area of these wells, the average fraction of initial oil-filled reservoir invaded by water is increased to only 9 pct.

Although a few cases exist where water

has fingered ahead completely by passing some wells, each of these has had only small water production. No cases exist of continued low water percentage production behind wells making large volumes of water. Thus not only does the water-encroachment performance confirm existence of quite low volume highly permeable streaks indicated by fractures in cores, but in addition it proves a reasonable degree of continuity of these streaks throughout the reservoir, a factor that can only be inferred by the frequency of fractures in cores examined.

Considering only this area invaded by a net 12 million barrels of water and having wells producing in excess of 25 pct water, it is well to consider equivalent performance with gas injection. During December 1946 these wells produced about 6300 bbl of oil per day and 14,000 bbl of water per day. It is reasonable to assume that the rock would have about the same effective permeability to gas as it does to water if free gas were to occupy the same position in the pore space. Reference to Leverett and Lewis' (Fig 14) three-phase fluid-flow study, the only published data,

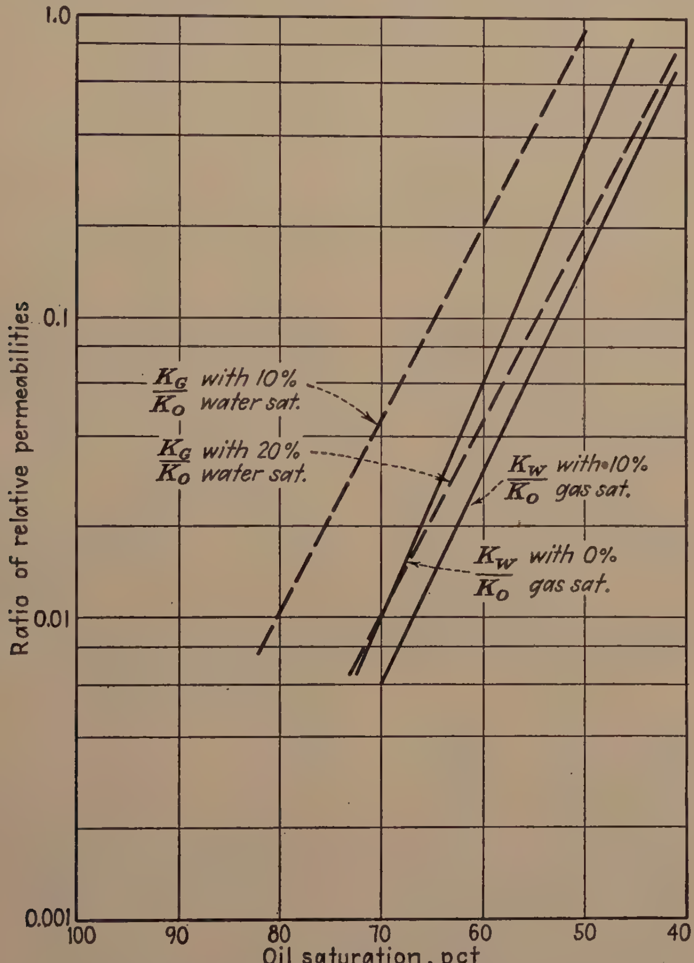

FIG 14—RELATIVE PERMEABILITY OF UNCONSOLIDATED SANDS TO OIL, GAS AND WATER. (Data from Leverett and Lewis *Petr. Tech.*, 1940)

shows this to be true for sands. At current pressures, the 12-million-barrel pore space would hold about 9 billion standard cubic feet of gas. Gas production equivalent to 14,000 bbl of water per day, after correcting for pressure and for the different viscosities of gas and water, would be about 300 million cubic feet per day at a gas-oil ratio of 47,000 cu ft per barrel. Thus if all wells were operated the same as current conditions, the entire stored gas would have to be cycled every 27 days. Extending this to the entire field with equivalent percentage pore space in fractures occupied by free gas, the current gas-injection volume would have to be about 2 billion cubic feet per day.

If these volumes of gas were not injected, lower gas-oil-ratio oil production from the intergranular porosity into the fractures would reduce the gas saturation to that necessary to balance gas-flow capacity to the gas-injection volume.

Of course, conditions with gas injection would not be quite as serious as this implies, since many wells producing large volumes of water would not be operated with equivalent gas production. At least the water invasion and production performance points to serious difficulties in control of gas production with a full-scale gas-injection pressure-maintenance program.

M. Littlefield, L. L. Gray and A. C. Godbold (authors' reply)—Most differences of opinion as to the physical character of the West Edmond pool arise from two basic misconceptions. The first misconception is that the total "pay" section is uniform in character and is all effective "pay" section. As shown in Fig 7, this is not the case. Study of cores with particular attention to the relation of oil stain to porosity and permeability shows considerable vertical variation in the distribution of "producing" porosity and permeability. In general, the vertical distribution of fracture porosity is more uniform than is the distribution of oil-stained intergranular porosity. The second misconception is that no fractures are present or, if present, are not connected because the reservoir does not perform as it should if all "producing" porosity was contained in large fractures, amounting to cavernous voids. If such were the case, uniformity of pressures and gas-oil ratios, as well as gravity segregation would be expected. Fracturing of this magnitude did not occur at West Edmond, nor was such implied in the paper. It is not necessary that such a condition exist in order to have by-passing. The important point is the *contrast* between permeabilities of intergranular and fracture porosity. If one component had an effective permeability of 50,000 md and the other 500 md, the tendency for by-passing would be substantially the same as if they were respectively 100 md and 1 md, or 10 md and 0.1 md. However, in the former case, uniformity of performance might be expected, whereas the latter two examples would undoubtedly give variations between wells. Rock study indicates that about 10 pct of the producing porosity is in fractures and 90 pct is made up of intergranular voids. The infinite variations of combinations of these two types or porosity are apparent in Fig 7. One constant factor is the fracturing of rock with intergranular porosity. Fracturing of the limestone into blocks of the order of 6 in. is indicated by the incidence in cores of fractures of various types, including bedding planes. The latter are not included in computations of void space. Actually, the range in size of fractured limestone blocks is probably considerable. In the dolomites, sealing of fractures by recrystallization may introduce irregularities of fracture permeability, irrespective of the size of fracture blocks.

From rock study alone, proof of interconnection of fractures is the presence of oil stain in them in parts of the section where both the rock itself and the filling of the solution-enlarged fractures is unstained.

In commenting on the discussion offered by Mr. L. E. Elkins, of Stanolind Oil and Gas Company, we find that there is not too much disagreement in our viewpoints, the major difference apparently being in the degree of connection within the fracture system. Mr. Elkins states that the cycling of gas through the channels would probably result in substantial increased recovery by (1) "maintenance of economic producing rates," and (2) "keeping the permeable channels stripped to a minimum degree of the oil that continually will seep into that channel until the reservoir approaches its ultimate equilibrium." In this connection, Mr. Elkins is referring to

recycling in the final stages of depletion. Certainly, if gas were recycled in the permeable channels (fractures) as suggested, a considerable degree of communication would have to exist within the permeable channels between wells, and between groups of wells. If good connection in the fracture system extends over such an area as this, then it appears likely that it might extend over very large areas as we have indicated. After the reservoir has been depleted to the point where the seepage of oil into the channels controls the rate of recovery, it does not appear evident how gas recycling will yield oil at a greater rate than provided by the bleeding of oil from the intergranular rock. The injected gas would merely be sweeping out the oil bled into the channels, and could have no effect on the rate of bleeding except perhaps to retard it to the extent that the pressure decline is arrested. Possibly Mr. Elkins is referring to alternate recycling and shutdown periods at a low stage of depletion. Such a program might have considerable merit. As stated in the paper, the authors believe that a recycling program at depletion of the intergranular porosity would probably be feasible.

In regard to the suggestion that oil may move out faster at some optimum intermediate pressure differential in place of absolute minimum differentials and absolute maximum differentials, the basic principles of reservoir mechanics are contradicted because it is required that flow rates increase with decreasing outflow pressure.

Mr. Jack Tarner, of Phillips Petroleum Company, does not agree that fractures, as such, exist in the reservoir, but suggests rather that fractures observed in cores were formed in the coring process by the release of overburden pressure. Although some fractures do result from mechanical stresses along previous lines of weakness, such fractures are easily recognizable, and none of these were included in computation of void space.

In commenting further on Mr. Tarner's discussion, no claim is made by the authors that filled fractures contribute to production and they are not included in computations of void space. As a matter of interest, they are shown in Fig 4, on the right side of the lithologic column under intermediate porosity. The legend shows this to be nonproductive. Filled fractures are common in the Frisco member, amounting to more than 5 pct of the volume in some layers. The computed figure for open fractures for the Frisco in the Streeter well is .07 pct.

In Fig 6, both the left-hand and center specimens have open vertical fractures which extend the full length of the specimen. It is true that some late fractures do terminate vertically on bedding planes. It is also true that some continue through the core, the maximum observed distance being 5 ft, on a nearly vertical break which came in one side of the core and out on the other side. The right-hand specimen in Fig 6 shows a pattern of echelon fractures in dolomite. The fact of fewer fractures in dolomite and of the tendency toward sealing by recrystallization is stated in the paper.

The center specimen of Fig 6 has a flat fracture face the whole length of the core. This represents a late fracture which cuts both early solution-enlarged fractures and the solution-made intergranular porosity. Without question, fractures through relatively dense limestone into limestone of good intergranular porosity do afford channels of communication to areas of fine porosity which are otherwise virtually isolated.

Mr. Tarner concludes that the average productivity index for the field is on the order of 2:1 and further concludes that the producing section would need from only 10 to 20 md permeability to have this productivity index. Obviously, Mr. Tarner is assuming that the "thick producing sections" are all effective pay. As stated previously, this was one of the "misconceptions" as core studies showed. Actually, the measured intergranular permeabilities, as shown in this paper, have only 1/10 of the value necessary to obtain a P.I. of 2.1. It was essential that a very *substantial* contribution by a fracture system would have been necessary in order to obtain the productivities that *actually* existed. Submitted in Fig 7 in the paper is a summary of the core data as evidence that the actual millidarcy feet obtained were only a small fraction of the minimum required for a P.I. of 2.1.

It was thought that some economic benefit might possibly be realized by unitized operation, permitting selective production. Certainly the uncontrolled advance of water through the fracture system is not good practice and under unitized operations it is believed

that water could be kept from advancing much farther if water-producing wells could be operated even beyond their economic limits. Moreover, we have made no claim that gas injection would not give some additional recovery. However, we do believe that the large projected investment and operating costs necessary to full-scale high pressure pool-wide gas injection would not be profitable, or at best it would be highly questionable. Whereas gas injection is an expensive process, selective well production is not. Actually, selective production, including operation of the water-producing wells, would cost less than competitive operations, because the total well-months operated should be substantially less than well-months operated under normal competitive operations.

We have stated in general terms that communication existed within the fracture system, admitting at the same time, however, that the degree of communication within the fracture system was highly variable, particularly in the northern portion of the pool which is largely dolomite. We have no cores from this area, but have recognized the probability that fewer fractures exist. This, of course, results in greater pressure differentials between wells and lower P.I. values. No statement has been made in the paper that the fracture system is of uniform continuity throughout. Continuity from any given well may be appreciable in one direction, as evidenced from interference tests, but of much smaller degree in the opposite direction. Accordingly, this would not necessitate that all wells in the pool have the same bottom-hole pressure, the same gas-oil ratio, the same P.I. and the same incidence of fractures in order for the fracture system to be communicating throughout a large portion of the pool. Again the important point is the *ratio* of permeabilities between the two components and not absolute values of permeability. There are very large areas in the pool which *have* had similar pressure declines and small pressure differentials between wells.

Irrespective of the rock study made on cores from eight wells located generally down the central portion of the reservoir, it is not possible to hide from the fact that water encroachment to date has illustrated perfectly the point the authors wish to make. As Mr. L. F. Elkins, of Continental Oil Company, expresses it in his discussion, "Thus, not only does the water-encroachment performance confirm existence of quite low volume highly permeable streaks indicated by fractures in cores, but in addition it proves a reasonable degree of continuity of these streaks throughout the reservoir, a factor that can only be inferred by the frequency of fractures in cores examined." This area of water encroachment represents a considerable portion of the pool. Certainly, it is logical to reason then that by-passing of gas injected would largely duplicate the by-passing evidence already obtained by the manner of water encroachment.

The performance of the West Edmond Hunton reservoir will furnish data on the behavior of a combination of intermediate and intergranular porosity and permeability. Even though that combination seems almost hopelessly complex, possibly the effect of some factors may be judged by comparison with the behavior of reservoirs composed only of fracture porosity and with reservoirs made up entirely of low-permeability, intergranular, limestone porosity. Essential differences between intergranular limestone permeability and intergranular dolomite permeability suggest that they should be considered separately in attempts to analyze the factors which affect reservoir performance. Study of carbonate reservoirs should progress from those with a single type of porosity to those in which various types are combined.

Inasmuch as the success or failure of a pressure maintenance project from an economic standpoint is largely dependent upon the degree of by-passing to be expected, it is clear that a thorough knowledge of the reservoir rock is essential. The authors wish to take this opportunity to thank those who have given their time to discuss this paper. Moreover, we hope that further work of this nature on limestone and dolomite reservoirs will be done as a supplement to core analysis and performance data.

Calculated Recoveries by Cycling from a Retrograde Reservoir of Variable Permeability

By M. B. Standing,* Member AIME, E. N. Lindblad* and R. L. Parsons,* Member AIME

(Los Angeles Meeting, October 1946)

Abstract

The recovery of the heavier components from a gas cap or retrograde pool is shown to be the greatest when the sand is cycled with a dry gas at a low pressure. This conclusion is in direct opposition to the belief that the most efficient production program is pressure maintenance and cycling at or near the dew point.

The results are calculated from: (1) constant volume, variable composition pressure-volume-temperature tests on a mixture of trap gas and liquid from a producing well; (2) published equilibrium constant data and the measured composition of the dew-point material; and (3) the fact that in a sand section of homogeneous permeability, injected gas displaces reservoir gas nearly quantitatively.

The results are based on the simplifying assumption that variable permeability systems may be defined by the ratio of two statistical parameters, and that gas injected into an actual sand will behave as though the sand were composed of many layers, each of constant permeability.

Introduction

Pressure decline in gas-condensate type reservoirs is accompanied by the formation of a liquid phase throughout the reservoir. Over the past ten years the processing of the material from these types of reservoirs for the heavier hydrocarbon components and the return of the light fractions to the reservoir ("cycling") has become increasingly popular. It has often been stated that the purpose of such a program is to prevent the loss of the retrograde liquid phase formed in the reservoir.

The purpose of this paper is to present the results of laboratory tests and computations concerned with seveial possible methods of producing a gas cap or condensate type of reservoir.

The results show that the recovery of heavier hydrocarbons for this type of reservoir is not a maximum under conditions of cycling at or near the dew-point pressure. Instead, variations in permeability and the ability of the dry injected gas to revapoiize condensate, point to cycling at a considerably reduced pressure as the optimum production-method. In addition the paper suggests a way of evaluating sands for their permeability variation.

The calculations presented in the following sections of the paper are in terms of the production of the butanes and heavier fraction from the gas cap of a field which had an original pressure of approximately 3000 psi. Specifically, the calculations show:

1. To what extent the condensate formed in the reservoir after pressure decline can be recovered by the cycling of a dry absorber-plant gas through the sands.

2. Whether there would be greater recovery of hydrocarbons if cycling were instigated at the original reservoir pressure.

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In answering the above points, three factors determined the efficiency with which condensate is recovered from a sand. These factors are:

1. The ability of the dry absorber gas to vaporize the condensate in the sand.

2. The effect of bypassing, within a swept out area, due to permeablity variations in the sand.

3. The effect of well pattern on the volume of formation swept out by the injected gas.

Compositional and volumetric changes of reservoir gas and liquid phases during pressure decline and cycling can be calculated from equilibrium constant data and the original composition of the reservoir material. However, in the case of condensate systems, the quantities of liquid phase so calculated are so intimately connected with the equilibrium constant of the heaviest components in the system,[3] it is desirable to have the results of PVT and other tests to guide the calculations.

With respect to the effect of bypassing, on a local scale, due to permeability variations, the actual variations are so complex and so largely unknown that attempts are not made to refine the calculating procedure unduly, or to consider whether the flow should be radial or linear oı some more complicated form. Rather, the calculations are based on the simple supposition that the flow is linear through variable permeabilities in parallel.

While this paper shows only calculated results, a number of drawdown and cycling tests were conducted in a tube packed with unconsolidated sand originally containing dew-point material. The results of these tests verified the calculated results.

It is believed that the methods used in obtaining the results presented in this paper are of sufficient interest to warrant presenting them in some detail. The results will be presented in terms of 1000 cu ft of reservoir hydrocarbon space and the term Mcf will be used to designate volumes of gases measured under conditions of 60°F and 14.7 psia.

Behavior of the Reservoir Fluids During Pressure Decline

Samples of gas and liquid from a high pressure trap were recombined in a PVT cell to give a dew point of 2960 psia at 195°F. The composition of this mixture is given in Table 1.

Table 1—*Composition of Gas-phase Material at* 2960 *Psia and* 195°F

Component	Mol Fraction	Gal per Mcf
Methane	0.7527	
Ethane	0.0766	
Propane	0.0441	
Butanes	0.0309	1.03
Pentanes	0.0221	0.84
Hexanes	0.0226	0.99
Heptanes plus	0.0530	2.54
	1.0000	5.40

Molecular weight C_7+ = 114
Density C_7+ = 0.755 60/60
Calculated gas gravity (air = 1) = 0.942
Calculated pseudocritical temperature = 449°F
Calculated pseudocritical pressure = 658 psia

The PVT behavior of the system was determined by removing successive small quantities of gas from the cell. Thermodynamic equilibrium was established after each removal. Retrograde liquid volumes and the gravity of the effluent gas were measured at each step. Such a procedure is equivalent to assuming the production of only gas-phase material from the reservoir. This is reasonable because oil will not flow from the reservoir at low liquid saturations.

In Fig 1 is shown the retrograde liquid obtained, expressed as a volume percentage. The maximum condensate was 8.25 pct at 1900 psia. Also shown in Fig 1 is the relation between the quantity of gas removed from the cell and the pressure.

The composition of the retrograde

[3] References are at the end of the paper.

liquid formed during pressure decline was computed on the basis of equilibrium constant data of Roland, Smith, and Kaveler,[9] the data presented in Fig 1,

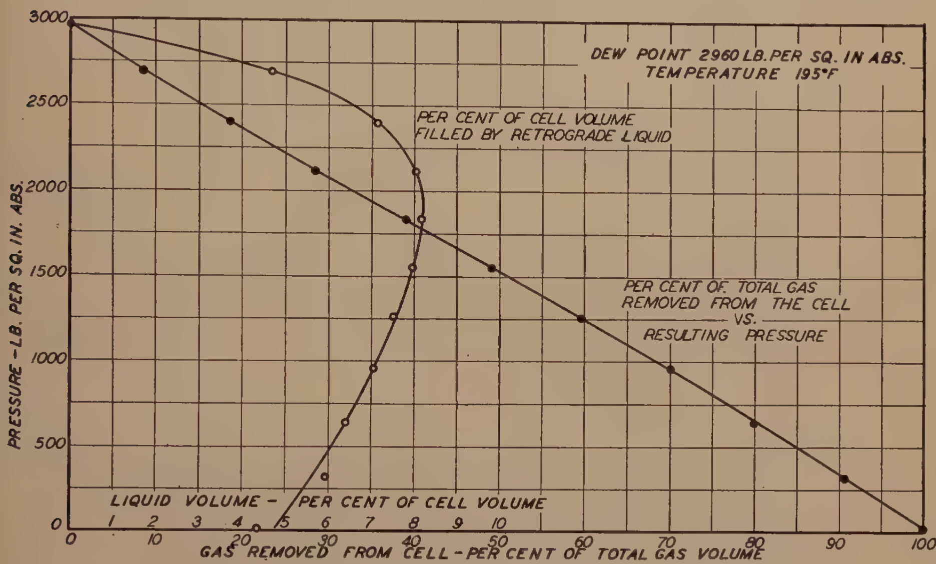

FIG 1—PVT BEHAVIOR OF THE DEW-POINT MATERIAL.

and apparent density data.[10] The calculation procedure considered the removal of successive small portions of equilibrium gas phase from the system, followed at each point by a new equilibrium between the gas and liquid remaining in the system. This scheme corresponded to the differential removal of gas phase from the PVT cell described above. At every point, however, the equilibrium constant of the Heptanes-plus fraction was adjusted until the calculated quantity of liquid in the system agreed with that determined experimentally in the PVT cell as shown in Fig 1. The calculated compositions of the coexisting liquid and gas phases, are shown in Figs 2 and 3.

The data of Figs 1, 2, and 3 in terms of field terminology are shown in Fig 4, which shows a maximum liquid volume at 1900 psia. At this pressure, 31 pct of the liquid is propane and lighter fractions.

BEHAVIOR OF THE RESERVOIR FLUIDS DURING DRY GAS INJECTION

The initial problem which must be solved is the behavior of the materials in a constant permeability section into which dry gas is injected. The results obtained will form a basis for estimating the behavior of a variable permeability sand. It is assumed that no mixing takes place between the injected gas and the reservoir gas. The problem then reduces to the calculation of the enrichment of the dry injection gas by contact with the liquid condensate as the dry gas proceeds through the sand.

The process used in this study can be made clear if one visualizes a sand tube of constant cross section, porosity and permeability divided into an arbitrary number of sections along its axis. Retrograde liquid and rich gas in equilibrium with the liquid are originally present in the pores of the sand tube. Dry gas is injected into the tube at one end and at the same time rich gas is produced from the opposite end. Under these con-

ditions the first quantity of injected gas will be progressively enriched by contact with the retrograde liquid as it advances into successive sections of the tube. compositions obtained from Fig 2 and 3, and the quantity of liquid from Fig 4.

In terms of the above description of the method and for a constant permea-

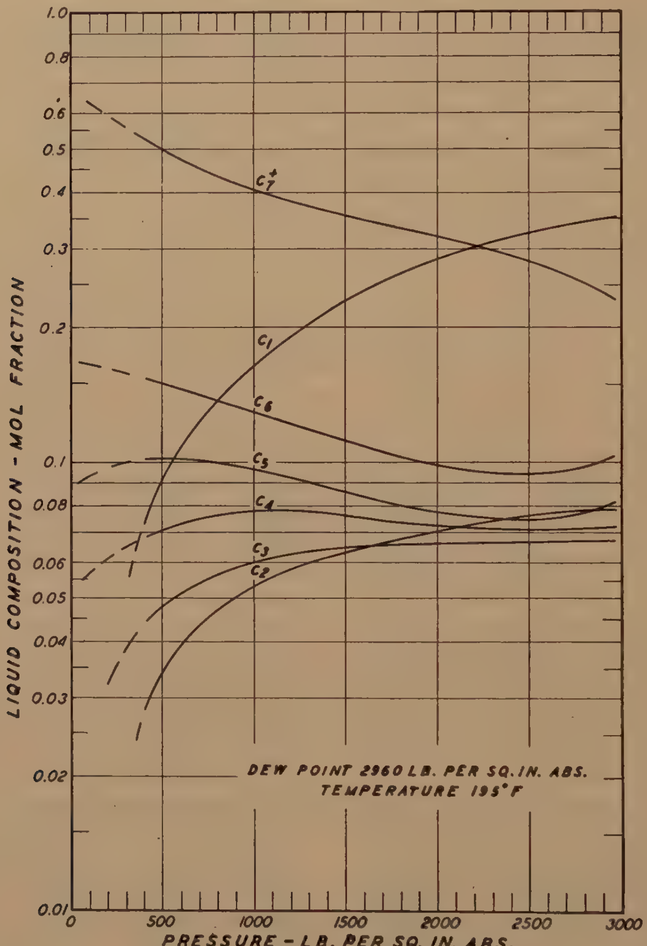

Fig 2—Liquid-phase composition.

On the other hand, as long as liquid exists in the first section of the tube it will be contacted with fresh dry gas.

Calculations on the basis of the above were carried out for injection pressures of 1310, 860 and 400 psia using the dry injection gas composition shown in Table 2, the retrograde liquid and rich gas bility section, it was found that at 1310 psia the first portion of dry gas introduced into the hypothetical sand tube became saturated with material from the liquid phase after 9 equilibrium steps. Also, at the same time the calculations indicated that all of the liquid would be vaporized by the passage of 3 volumes of dry injec-

tion-gas. It is clear that these volumes, necessary to accomplish a particular amount of liquid pickup, are dimensionless. That is, if 3,000 cu ft of gas, under reservoir conditions, will vaporize all the liquid in 1,000 cu ft of hydrocarbon space, by the process assumed in the calculations, then 3 cu ft of gas will vaporize the liquid in 1 cu ft of hydrocarbon space. To generalize, then, for the system studied at 1310 psia, a point in a linear system becomes dry when a volume of gas equal to three times the pore volume between the point and the injection face has been injected into the system. Fig 5 shows the liquid saturation and the gas composition in a linear system of unit pore volume when 0.5, 1.0, 2.0, and 2.8 pore volumes of gas have been injected. An immediate conclusion of these results is that a system, originally containing a liquid phase and a gas in equilibrium, into which a dry gas is injected, is composed of three distinct regions: first a region in which all the liquid has been vaporized, followed by a region of increasing liquid saturation,

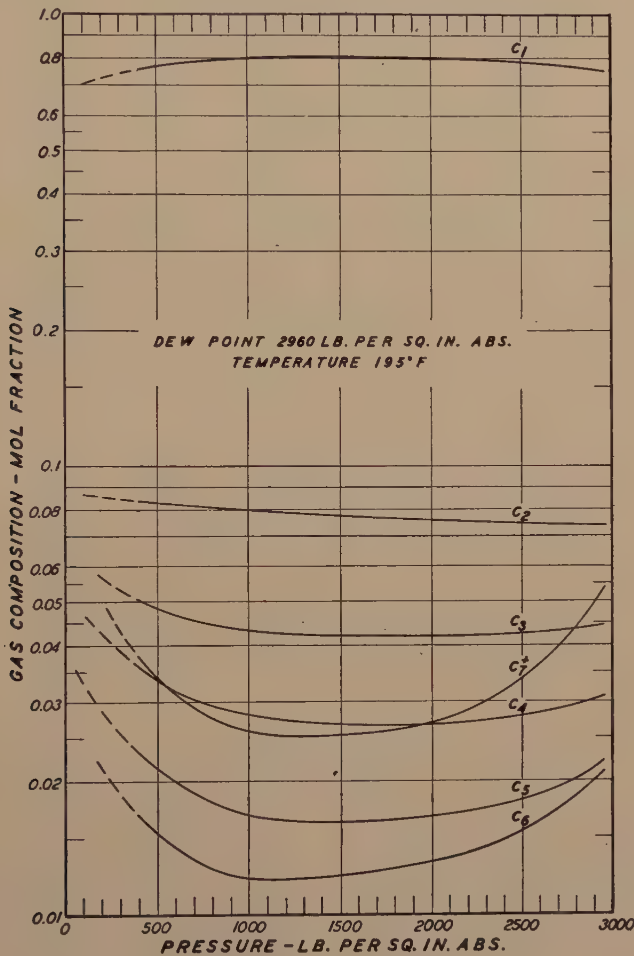

Fig 3—Gas-phase composition.

and finally a region of the original composition. All three regions exist immediately upon gas injection, and only their size changes with increased injection while region 3 occupies the remainder of the sand. Referring again to Fig 5, after the injection of 0.5 pore volumes, the first 17 pct of the reservoir is dry

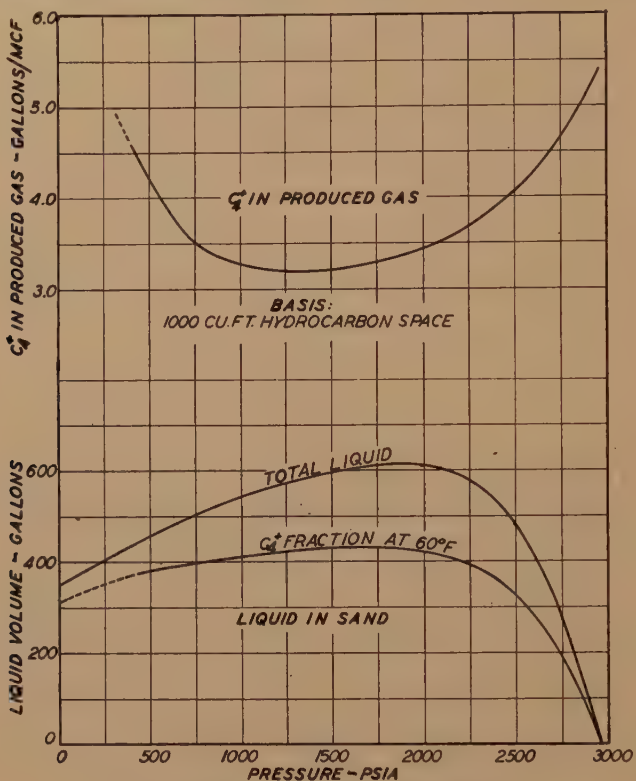

FIG 4—LIQUID-VOLUMES VS. PRESSURE.

volume. The size of regions 1 and 2 is fixed by the quantity of injected gas, (3 times the pore volume in the first 17 pct has been injected); and 33 pct of the reservoir is region two. The remaining half is region three. When the volume of injected gas has increased to 1.0 pore volumes, the first 33 pct is dry, the remainder of the reservoir is region two and region three has disappeared.*

TABLE 2—*Composition of the Dry Injection Gas*

Component	Mol Fraction	Gal per Mcf
Methane	0.8814	
Ethane	0.0846	
Propane	0.0294	
Butanes	0.0018	0.06
Pentanes	0.0008	0.03
Hexanes	0.0009	0.04
Heptanes plus	0.0011	0.06
	1.0000	0.19

Calculated gas gravity (air = 1) = 0.632
Calculated pseudocritical temperature = 372°R
Calculated pseudocritical pressure = 672 psia

* An exact analogue of the process may be visualized by picturing a rubber tape, representing composition, lying parallel to a ruler, representing the reservoir. The tape and ruler are each one foot long and are attached at the injection end. For 0.5 pore volumes injected, the first two inches of the tape are painted white for region one and the next four inches are painted red for region two. The fraction of the reservoir occupied by each region for

For a particular cycling test, as shown in Fig 5, the composition of the effluent gas may be calculated as a function of the quantity of injected gas. The liquid content and all the vaporized liquid has been displaced by injected gas (Fig 7).

Fig 7 shows that the ability of the dry gas to become saturated with the liquid

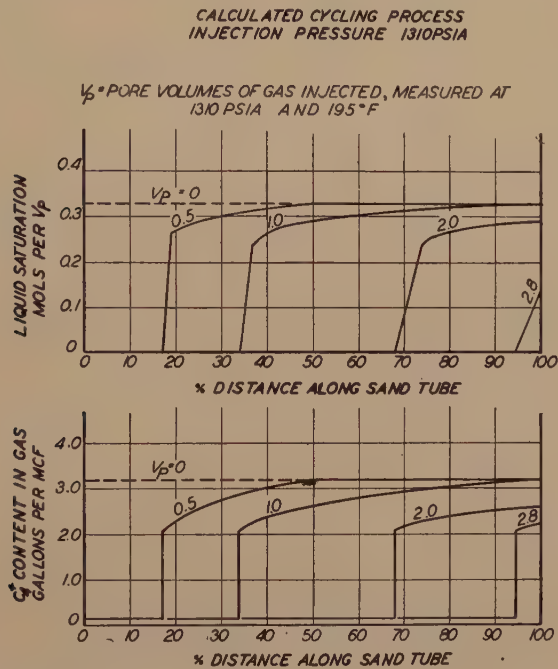

FIG 5—CALCULATED-REGIONS ALONG A SAND TUBE.

of the sand may also be expressed as a function of the quantity of injected gas. Results for these cycling pressures investigated are shown in Figs 6, 7, and 8.

Referring to Fig 6 and specifically to the 1310 psia pressure, the composition of the first gas produced is 3.2 per gallons per Mcf of butanes plus, and corresponds to the composition of the rich gas in the reservoir. The gas produced in the region corresponding to 65 to 196 Mcf injection gas is dry injection gas which has been enriched by "picking up" the retrograde liquid from the sand. Beyond 196 Mcf of injection gas the composition of the injected and produced gases are the same, i.e. no more liquid remains in the sand

different quantities of injected gas may be read directly by stretching or compressing the tape.

condensate is approximately the same at the three pressures investigated, i.e. the slopes of the curves are about equal at the ordinate of the chart. However, as there is less condensate initially present at the lower pressures, less injected gas is required to vaporize the liquid.

It should be emphasized here that the calculations so far do not indicate that all of the retrograde liquid can be recovered from a reservoir by cycling dry gas. They do indicate however, that the sand sections in a reservoir which are contacted by sufficient quantities of dry gas can be stripped of the retrograde liquid. The recovery mechanism discussed in succeeding sections will make this point clear.

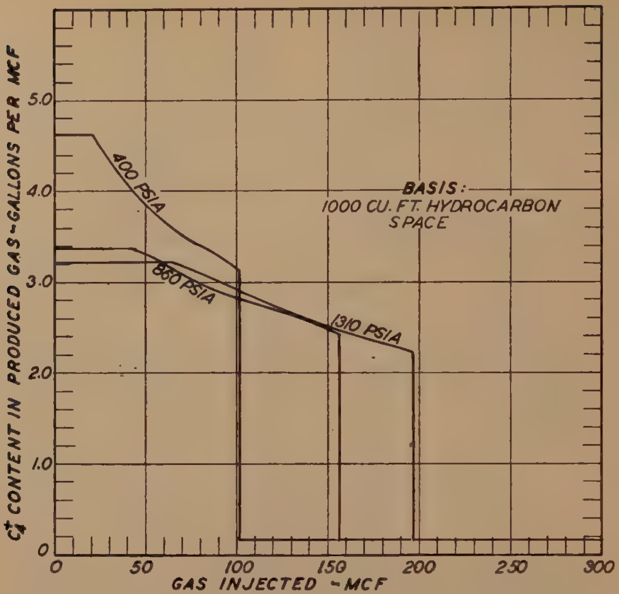

FIG 6—C_4 + CONTENT IN GAS PRODUCED FROM A SAND TUBE.

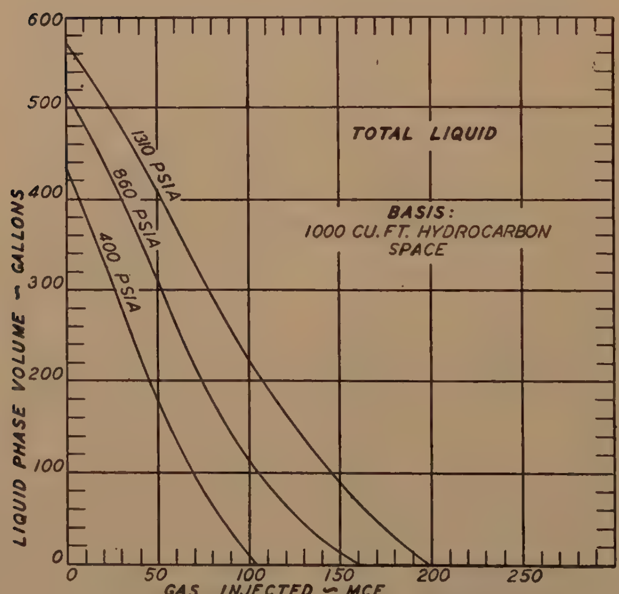

FIG 7—TOTAL LIQUID IN A SAND TUBE.

Effect of Variable Permeability

The recovery of rich gas from a sand body by the injection of dry gas, and the revaporization of retrograde liquid that has formed during pressure decline are materially influenced by the permeability distribution throughout the sand. Hurst and Van Everdingen,[6] considering only the displacement of rich gas by dry gas in a sand of variable permeability, have shown that recoveries as low as 35 pct of the rich gas can be expected.

For the purpose of this paper, the term coverage will be used to identify the fraction of the volume of a sand body that is swept out by injected gas. The coverage is always less than unity for two reasons: volumes of sand between injection wells and in other "potential deadspots" are bypassed (macroscopic coverage); and within the swept out area, smaller portions of sand are partially or completely bypassed because of variations in permeability (microscopic coverage).

The microscopic coverage depends not only upon local permeability variations in the sand, but also upon the relative mobility* of the driving and driven phases. However, for the case of a dry gas driving a wet gas, the relative mobility ratio is unity for all practical purposes, so that the problem reduces to that of determining the microscopic coverage as a function of the variation in permeability.

To illustrate the principle of the relationship between microscopic coverage and the variation of permeability, consider the following system: a linear block composed of layers separated from each other by thin impermeable streaks. The layers have permeabilities k_1, k_2, $k_3 \ldots k_n$. Suppose that the block contains a rich gas, r, which is being displaced by an injected gas, i. At any time, the interface between i and r in each layer will be at a distance from the injection face that is proportional to the permeability of the layer.*

If the permeabilities are known, the coverage can then be calculated for particular amounts of injected gas.

In practice, permeability variation is not so simple as described above, and a complete knowledge of the permeability variation over the reservoir is not possible. A simplifying assumption is required. The substitution of the actual variable system with one containing the same amount of variation, but composed of layers, each of constant permeability, is generally recognized as acceptable.

The definition of "the amount of variation" was chosen so that two different sands, with two different permeability profiles, would have the same "variation" if their microscopic coverage were the same for equal amounts of injected gas.

For example, consider two systems, each consisting of two layers. The first system has layer permeabilities of 50 and 100 millidarcys; the second has layer permeabilities of 200 and 400 millidarcys. The coverage by the injection of one pore volume of gas is the same for both systems. The systems have by definition the same permeability variation. Consider now the more general case of a system composed of many layers. The permeabilities are plotted on logarithmic probability paper and the best straight line is drawn through the points.† The median permeability is read at the 50 pct line. The permeability above which 84.1 pct of the permeabilities lie is also read from the plot. The difference between these two permeabilities is divided

* The ratio of the relative permeability of a fluid phase to its viscosity is called the mobility; and the ratio of the mobility of the driving fluid to the mobility of the driven fluid is called the relative mobility-ratio.

* This is not strictly true for a gas because the density varies with the pressure, but it is accurate enough for the purpose and the methods of calculations to be used.

† For some purposes, all the permeabilities are expressed as a per cent of the maximum permeability appearing in the distribution. This has been done in Fig 9. This step is not necessary, however, for computing the "variation."

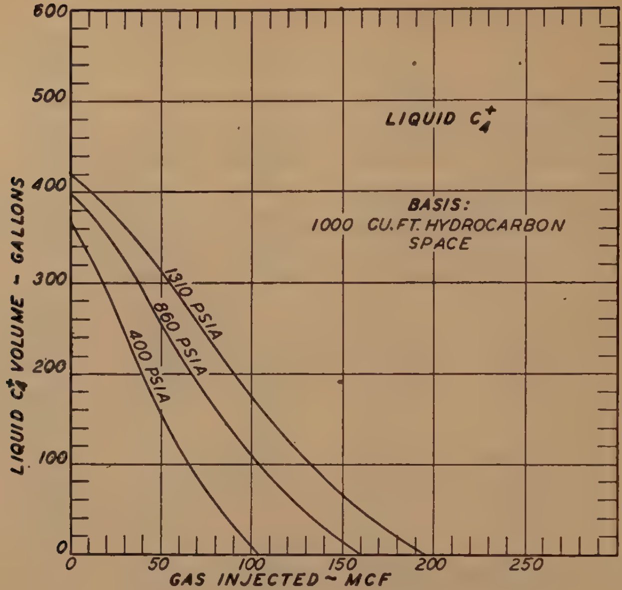

Fig 8—C_4 + liquid in a sand tube.

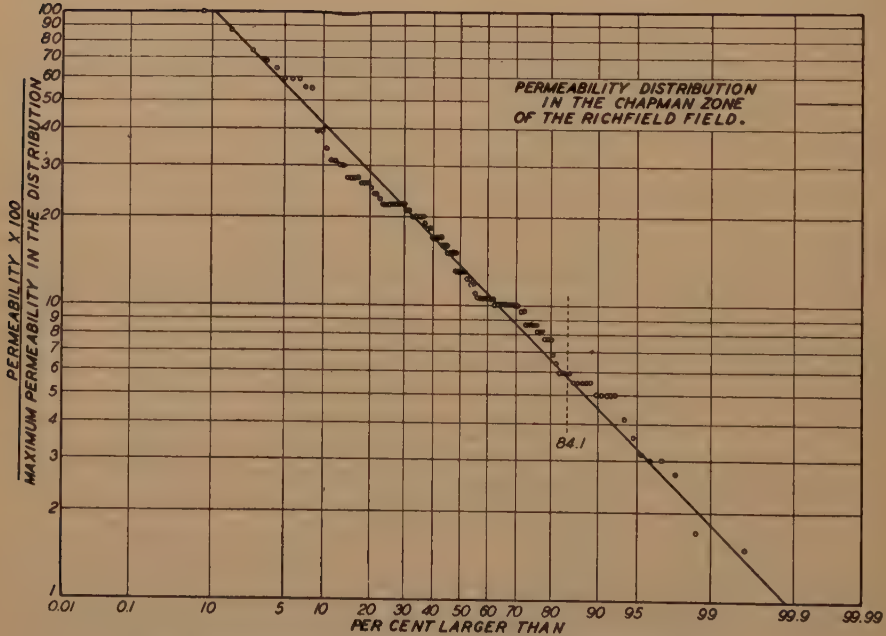

Fig 9—Permeability-distribution in the Richfield field.

by the median permeability, and the ratio is called the variation. The microscopic coverage of two sand bodies will be the same if their permeability variation is the same. Table 3 gives the permeability variation for several sands appearing in the literature, and Table 4 gives the

TABLE 3—*Permeability Variation of Oil Sands*

Sand	Permeability Var.	Ref.
Chapman zone, Richfield field, Calif.	0.58	1
Lower Rigoleto zone, Lafitte field, La.	0.80	11
Sand well A, South Texas	0.60	2
Gulf Coast field	0.79	6
Coregraph No. 1, Bradford field, Pa.	0.80	5
Coregraph No. 2, Bradford field, Pa.	0.49	5
Well No. 220, Neosho County, Kans.	0.73	4
Well No. 1, Neosho County, Kans.	0.74	4
Well No. 9, Neosho County, Kans.	0.85	4
Slaughter field, Permian Basin, Texas	0.70	8
Dominquez field, Southern California		
Shallow depth	0.35	7
Middle depth	0.59	7
Deep depth	0.57	7

TABLE 4—*Percentage of Reservoir Swept over n Times by Injected Gas for Different Permeability Variations and for Different Amounts (Pore Volumes) of Injected Gas*

Volume of Injected Gas, Pore Volumes[a]	n = 0	1	2	3	4	5	6	7
Variation of 0.30								
0.0	100	0	0	0	0	0	0	0
0.2	80	20	0	0	0	0	0	0
0.4	60	40	0	0	0	0	0	0
0.6	40	60	0	0	0	0	0	0
0.8	23	75	2	0	0	0	0	0
1	11	79	10	0	0	0	0	0
1.5	2	55	35	7	1	0	0	0
2	1	27	49	17	6	0	0	0
2.5	1	11	45	25	15	3	0	0
3	1	1	34	33	23	8	0	0
4	0	0	17	28	25	18	9	3
5	0	0	7	18	23	20	14	6
6	0	0	1	11	17	18	16	11
8	0	0	0	3	8	12	14	14
10	0	0	0	0	3	7	9	11
15	0	0	0	0	0	0	2	4
20	0	0	0	0	0	0	0	1
30	0	0	0	0	0	0	0	0
50	0	0	0	0	0	0	0	0
100	0	0	0	0	0	0	0	0
Variation of 0.40								
0.0	100	0	0	0	0	0	0	0
0.2	80	20	0	0	0	0	0	0
0.4	60	40	0	0	0	0	0	0
0.6	42	57	1	0	0	0	0	0
0.8	29	61	10	0	0	0	0	0
1	19	62	18	1	0	0	0	0
1.5	8	48	32	10	2	0	0	0
2	2	34	36	17	10	1	0	0
2.5	1	24	32	21	14	7	1	0
3	1	15	27	24	16	10	6	1
4	0	0	20	20	18	13	8	6
5	0	0	14	17	16	14	10	8
6	0	0	9	13	14	13	12	10
8	0	0	0	8	10	10	10	10
10	0	0	0	4	7	8	8	8
15	0	0	0	0	1	3	5	5
20	0	0	0	0	0	0	2	3
30	0	0	0	0	0	0	0	0
50	0	0	0	0	0	0	0	0
100	0	0	0	0	0	0	0	0
Variation of 0.50								
0.0	100	0	0	0	0	0	0	0
0.2	80	20	0	0	0	0	0	0
0.4	60	40	0	0	0	0	0	0
0.6	45	51	4	0	0	0	0	0
0.8	35	53	10	2	0	0	0	0
1	26	53	17	4	0	0	0	0
1.5	11	48	26	10	5	0	0	0
2	4	39	28	15	9	4	1	0
2.5	2	31	27	18	11	7	4	0
3	1	24	25	19	13	9	6	4
4	1	14	21	18	14	10	8	6
5	0	6	16	16	13	11	9	7
6	0	0	13	14	13	11	9	8
8	0	0	7	10	10	10	9	8
10	0	0	3	7	8	8	8	7
15	0	0	0	2	4	5	6	6
20	0	0	0	0	2	3	4	4
30	0	0	0	0	0	0	1	2
50	0	0	0	0	0	0	0	0
100	0	0	0	0	0	0	0	0
Variation of 0.60								
0.0	100	0	0	0	0	0	0	0
0.2	80	20	0	0	0	0	0	0
0.4	60	39	1	0	0	0	0	0
0.6	49	43	8	0	0	0	0	0
0.8	38	45	15	2	0	0	0	0
1	30	45	20	4	1	0	0	0
1.5	16	44	22	10	6	2	0	0
2	11	40	22	12	8	5	2	0
2.5	7	36	22	14	10	7	3	1
3	5	32	22	15	11	8	4	2
4	3	25	20	15	11	9	6	4
5	2	19	18	14	11	9	7	5
6	1	14	16	13	11	9	7	6
8	1	5	12	11	10	9	7	6
10	0	0	9	9	9	8	7	6
15	0	0	3	6	6	6	6	5
20	0	0	0	3	5	5	5	4
30	0	0	0	0	2	3	3	3
50	0	0	0	0	0	0	1	1
100	0	0	0	0	0	0	0	0

TABLE 4—(*Continued*)

Volume of Injected Gas, Pore Volumes[a]	*n*							
	0	1	2	3	4	5	6	7
Variation of 0.70								
0.0	100	0	0	0	0	0	0	0
0.2	80	20	0	0	0	0	0	0
0.4	64	32	4	0	0	0	0	0
0.6	53	35	11	1	0	0	0	0
0.8	45	35	15	5	0	0	0	0
1	38	36	16	8	2	0	0	0
1.5	27	36	16	9	6	3	2	1
2	20	35	16	10	8	5	3	2
2.5	16	33	16	10	8	6	4	3
3	12	31	16	10	8	7	5	4
4	8	27	16	10	8	7	5	5
5	5	23	15	10	8	7	5	5
6	4	20	14	10	8	7	5	5
8	2	14	12	10	8	7	5	5
10	2	10	10	9	8	6	5	5
15	1	4	7	7	6	6	5	5
20	1	3	5	5	5	5	4	4
30	1	1	2	3	3	4	4	4
50	0	0	0	1		2	2	2
100	0	0	0	0		0	0	1
Variation of 0.80								
0.0	100	0	0	0	0	0	0	0
0.2	81	19	0	0	0	0	0	0
0.4	69	24	6	1	0	0	0	0
0.6	59	27	9	5	0	0	0	0
0.8	52	28	11	7	2	0	0	0
1	46	29	12	8	4	1	0	0
1.5	37	29	12	8	5	3	2	2
2	33	29	12	8	6	4	3	2
2.5	30	28	12	8	6	5	4	3
3	27	28	12	8	6	5	5	3
4	22	26	12	8	6	5	4	3
5	20	24	12	8	6	5	4	3
6	17	23	12	8	6	5	4	4
8	14	20	11	8	6	5	4	4
10	11	18	10	8	6	5	4	4
15	6	14	9	7	6	5	4	3
20	4	10	8	6	5	4	4	3
30	3	3	6	5	5	4	3	3
50	1	1	3	3	3	3	3	3
100	0	0	0	1	1	2	2	2

[a] Example: After injection of 1.5 pore volumes, 2 pct remains unswept; 55 pct has been swept over once; 35 pct, twice; 7 pct, 3 times; 1 pct, 4 times; and none 5 times or more.

amount of bypassing as a function of the variation and the amount of injected gas.

The variation is not an accepted statistical definition, but it is easy to compute. If the permeabilities are expressed as suggested by Law,[7] then $V = 1 - 2^{\frac{-\sigma\phi}{2}}$ where V is the variation, $\sigma\phi$ is the standard deviation of the ϕ distribution, $\phi = \log_{\sqrt{2}} \frac{k}{10}$, and k is the permeability in millidarcys.

To illustrate the use of Table 4, Fig 9 shows a plot of the permeability profile of a California oil sand.[1] The median permeability is 13.8, and the permeability at the 84.1 pct line is 5.8. The difference is 8.0, and the variation is $\frac{8.0}{13.8} = 0.58$. By interpolation from Table 4, after the injection of 2 pore volumes, 9 pct of the reservoir remains unswept; 40 pct has been swept by one pore volume; 23 pct has been swept by 2 pore volumes; 12 pct has been swept by 3 pore volumes; and no part of the reservoir has been swept by 7 or more pore volumes.*

TABLE 5—*Percentage of Reservoir Swept Over n Times by Injected Gas for Permeability Variation of* 0.55 *and for Different Amounts (Pore Volumes) of Injected Gas*

Volume of Injected Gas, Pore Volumes	*n*							
	0	1	2	3	4	5	6	7
0.0	100	0	0	0	0	0	0	0
0.2	80	20	0	0	0	0	0	0
0.4	60	40	0	0	0	0	0	0
0.6	47	47	6	0	0	0	0	0
0.8	36	49	13	2	0	0	0	0
1	28	49	18	4	1	0	0	0
1.5	13	46	24	10	6	1	0	0
2	7	40	25	13	9	5	1	0
2.5	5	33	25	16	10	7	3	1
3	3	28	24	17	12	8	5	3
4	2	19	21	17	13	9	7	5
5	1	12	17	15	12	10	8	6
6	1	7	14	13	12	10	8	7
8	0	3	9	10	10	9	8	7
10	0	0	6	8	8	8	7	6
15	0	0	2	4	5	5	6	5
20	0	0	0	1	3	3	4	4
30	0	0	0	0	1	1	2	3
50	0	0	0	0	0	0	1	1
100	0	0	0	0	0	0	0	0

* For injection gas, a pore volume is the volume of the hydrocarbon space within the boundaries of the surface which traces the fartherest advance of the injected gas in all directions. For parts of the reservoir, the statement "40 pct has been swept by one pore volume" means that 40 pct of the volume

Fig 10 shows the producing ratio of injected to original reservoir gas for different quantities of injected gas. This chart is calculated from Table 4.

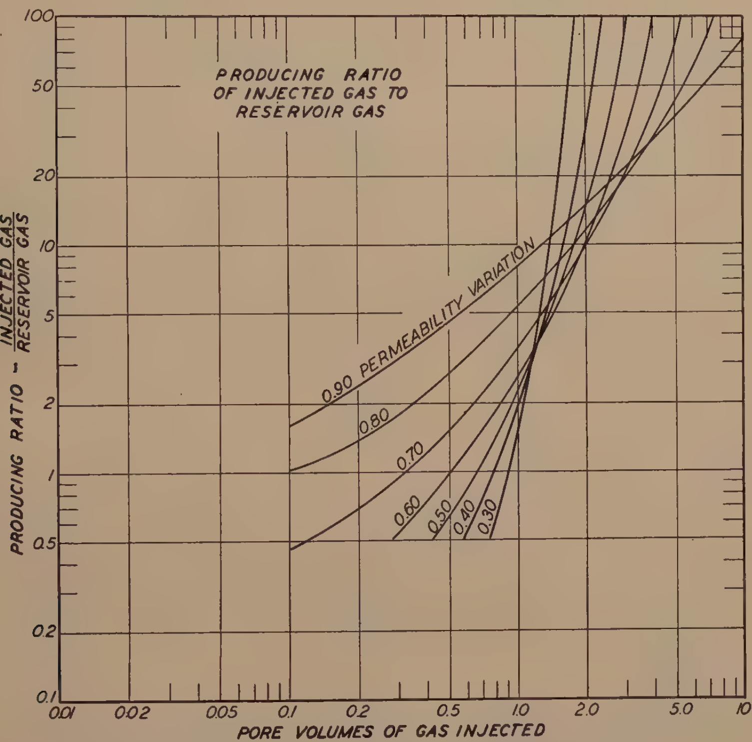

FIG 10—PRODUCING RATIO OF INJECTED TO RESERVOIR GAS.

sure maintenance at the dew point of 2960 psia by gas injection, and depletion to 1310, 860, or 400 psia followed by dry gas-injection at those pressures. These calculations will be made for a sand having a permeability variation of 0.55.

The use of the microscopic coverage-data presented in Table 4 and the thermodynamic data presented in the first section of this paper allows one to compute the hydrocarbon recovery as a function of the quantity of gas injected into the sand. As an example of this, the recovery of gallons of butane-plus fraction from 1000 cu ft of "active" reservoir hydrocarbon space will be calculated under four different production methods: pres-

Table 5 presents the behavior of the injection gas in a sand having the permeability variation of 0.55. The data of this table were obtained by interpolation from Table 4. These data are basic for all of the calculations to follow.

Pressure Maintenance at 2960 Psia by Injection of Dry Absorber-plant Gas

The flow behavior of the injected gas is given in Table 5. The C_4+ content calculated from its composition (Table 2) is 0.19 gal per Mcf. The C_4+ content of

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described above has had injected gas pass into it once, while the statement "23 pct has been swept by 2 pore volumes" means that 23 pct of the total volume has had injected gas pass into it twice. Thus the total quantity of injected gas is 0.40 × 1 + 0.23 × 2 + 0.12 × 3 + . . . = 2 pore volumes.

the rich reservoir gas at 2960 psia is 5.40 gal per Mcf (Table 1). On the unit basis of 1000 cu ft of pore space, the reservoir contains at 2960 psia and 195°F, 1100 gal of C_4+ in 204 Mcf of gas. When filled with dry gas at 2960 psia and 195°F, the reservoir contains 35 gal of C_4+ in 182 Mcf.

is necessary to determine the quantity of material existing in the reservoir at the start of the injection process. During the pressure reduction process, the composition of the effluent is independent of the permeability variation.

A summary of these calculations is given in Table 7.

TABLE 6—*Recovery of* C_4+ *by Pressure Maintenance at* 2960 *Psia*

Volume of Injected Gas: Pore Vol.	Volume of Injected Gas: Mcf	Fraction of Reservoir Swept by no Pore Vol.	Gallons of C_4+: Injected	Gallons of C_4+: Reservoir Content	Gallons of C_4+: Gross Produced	Gallons of C_4+: Net Produced	Produced Gas, Mcf	Producing Ratio, Gal C_4+ per Mcf
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
0	0	1.00	0	1,100	0	0	0	5.40
0.2	36	0.80	7	887	220	220	41	5.40
0.4	73	0.60	14	674	440	440	82	4.90
0.6	109	0.47	21	536	585	583	121	3.50
0.8	145	0.36	28	418	710	704	160	2.70
1.0	182	0.28	35	333	802	793	198	2.20
1.5	273	0.13	52	173	979	959	293	1.20
2.0	364	0.07	68	109	1,059	1,023	385	0.68
2.5	455	0.05	86	88	1,098	1,045	476	0.45
3.0	546	0.03	104	67	1,137	1,068	568	0.31
4.0	728	0.02	138	56	1,182	1,080	750	0.24
5.0	910	0.01	173	46	1,227	1,090	932	0.21
		0.00		35		1,100		0.19

Notes on Calculation Methods

(2) $V_i = V_p \cdot \frac{P_2T_1Z_1}{P_1T_2Z_2}$

$= V_p \cdot \frac{2960}{14.7} \cdot \frac{520}{655} \cdot \frac{1}{0.88}$

$= 181.8V_p$

(3) From Table 5

(4) Injected gas contains 0.19 gal C_4 per Mcf. Item 4 = 0.19 · item 2.

(5) The initial C_4+ content, all in the gas phase, is 1100 gal per 1000 cu ft of reservoir space. (See Table 7). The C_4+ content of that portion of the reservoir containing injected gas is 35 gal per 1000 cu ft. Therefore, the C_4+ content of the reservoir is 1100 · item 3 + 35[1 − item 3].

(6) Gross produced = original + injected − reservoir content. Item 6 = 1100 + item 4 − item 5.

(7) Net produced is the amount of the original content produced. Item 7 = 1100[1 − item 3].

(8) Produced gas is part rich gas and part injected gas. The injection of one pore volume of gas produces one pore volume, which is composed of 0.28 pore volumes of injected gas and (1 − 0.28) volumes of rich gas. Item 8 = 181.8{item 1 − [1 − item 3]} + 204 [1 − item 3]
= 181.8[item 1 + item 3 − 1] + 204[1 − item 3].

(9) Slope of the curve obtained by plotting item 6 vs item 8, or better, by performing graphical differentiation of data shown in items 6 and 8 and smoothing results.

Table 6 gives a summary of the calculations for pressure maintenance at 2960 psia together with an explanation of the methods of calculation.

PRESSURE DRAWDOWN FROM 2960 PSIA WITHOUT GAS INJECTION

Prior to determining the effect of injecting gas at the lower pressures it

PRESSURE MAINTENANCE AFTER DRAWDOWN FROM 2960 PSIA

Again it is necessary to make use of the data presented in Table 5. This calculation differs from that outlined in Table 6 because in addition to displacing the rich reservoir gas, the injected gas revaporizes liquid that has condensed during the

pressure decline from 2960 to 1310 psia. Fig 8 shows the C_4+ in the sand as a function of the quantity of injected gas.

Table 8 gives a summary of the total quantity of C_4+ (expressed as gallons of liquid) in 1000 cu ft of reservoir space after being contacted with various quantities of dry injection-gas at 1310 psia. These data are for a section of homogeneous permeability and when used with the data of Table 5 will give recovery for the section having a 0.55 permeability distribution.

Table 9 presents the calculations for the recovery of C_4+ at 1310 psia by injecting dry gas. The results of calculations for injection at 860 and 400 psia are included at this point in Tables 10 and 11.

In Fig 11, are plotted the productions

TABLE 7—*Effect of Pressure Decline on* C_4+ *Distribution*

Pressure, Psia	Gas Produced		Per Pressure Interval			Total C_4+ Produced, Gal	C_4+ in Reservoir, Gal	
	Pct	Mcf	Gas Produced, Mcf	Avg C_4+ Content, Gal per Mcf	C_4+ Produced, Gal		Liquid Phase	Vapor Phase
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
2,960	0	0	9.8	5.10	50.0	0	0	1,100
2,800	5.0	9.8	13.0	4.52	58.8	50.0	160	890
2,600	11.6	22.8	13.4	4.08	54.7	108.8	283	708
2,400	18.5	36.2	13.6	3.75	51.0	163.5	358	579
2,200	25.4	49.8				214.5	400	485
			14.1	3.52	49.7			
2,000	32.6	63.9				264.2	421	415
1,800	40.0	78.4	14.5	3.37	48.9	313.1	428	359
1,600	47.2	92.5	14.1	3.28	46.3	359.4	427	314
1,400	54.4	106.5	14.0	3.25	45.5	404.9	424	271
1,200	61.3	120.0	13.5	3.22	43.5	448.4	418	234
			13.5	3.23	43.6			
1,000	68.2	133.5				492.0	408	200
800	74.9	146.5	13.0	3.35	43.6	535.6	397	167
600	81.6	160.0	13.5	3.63	49.0	584.6	385	130
400	88.1	172.5	12.5	4.20	52.5	637.1	368	95

Notes on Calculation Methods

(2) Obtained from constant volume gas phase withdrawal PVT test. See Fig 1

(3) At 2960 psia and 195°F, 1000 cu ft of reservoir hydrocarbon space contains $1000 \cdot \frac{2960}{14.7} \cdot \frac{520}{655} \cdot \frac{1}{0.78} = 204$ Mcf of gas.

At 14.7 psia and 195°F, the total liquid remaining in the reservoir is 4.67 pct, or 46.7 cu ft per 1000 cu ft. From Fig 3 it is estimated that this liquid has a specific gravity of 0.658 at 195°F and a molecular weight of 101. Therefore, the vapor equivalent of the liquid phase is

$$46.7 \cdot \frac{(62.4 \cdot 0.658)}{101} \cdot 379 = 7.35 \text{ Mcf}$$

At 14.7 psia and 195°F the gas phase remaining in the reservoir is

$$1000(1 - 0.0467) \cdot \frac{520}{655} = 0.76 \text{ Mcf.}$$

Therefore, the gas produced in going from 2960 psia to 14.7 psia is $204 - (7.35 + 0.76) = 195.9$ Mcf. Item 3 $= 195.9 \cdot$ item 2

(4) Obtained by differencing item 3

(5) From Fig 4

(6) Item 6 = item $4 \cdot 5$

(7) Summation of item 6

(8) From Fig 4

(9) Original reservoir gas contains 5.4 gal C_4+ per Mcf. As shown above, 1000 cu ft of reservoir hydrocarbon space contains 204 Mcf of gas at 2960 psia and 195°F. Therefore, original C_4+ content of reservoir is $204.5 \cdot 4 = 1100$ gal. Gallons in gas phase at any pressure = original − produced − amount in liquid phase. Item 9 = 1100 − item 7 − item 8.

calculated in Tables 6, 9, 10 and 11 as a function of the quantity of gas injected. The intercepts on the ordinate for the injection pressures of 1310, 860, and 400 psia are the quantities of C_4+ obtained by pressure depletion from the original 2960 psia. The recoveries by cycling shown in this figure are only for the portion of the reservoir that has been swept by the injection gas. Fig 12 shows the composition of the produced gas.

TABLE 8—C_4+ *Content of Homogeneous Permeability Section after Being Contacted with Various Quantities of Injection Gas*

Volume of Injected Gas		C_4+ in Liquid Phase, Gal	Total C_4+ in Reservoir, Gal
Pore Volume	Mcf		
(1)	(2)	(3)	(4)
		1310 Psia	
0	0	422	677
1	78	230	437
2	156	55	245
3	234	0	70
4	312	0	15
5	390	0	15
		860 Psia	
0	0	398	577
1	50	250	408
2	100	115	260
3	150	15	125
4	200	0	25
5	250	0	10
6	300	0	10
		400 Psia	
0	0	368	463
1	22	282	372
2	44	180	286
3	66	76	184
4	88	34	100
5	110	0	38
6	132	0	4

Notes on Calculation Methods (1310 psia)

(2) Injection gas at 1310 psia and 195°F

$$V_i = V_p = \frac{P_2}{P_1}\cdot\frac{T_1}{T_2}\cdot\frac{Z_1}{Z_2}$$

$$V_i = V_p\cdot\frac{1310}{14.7}\cdot\frac{520}{655}\cdot\frac{1}{0.91} = 78V_p \text{ or } 78\ (1)$$

(3) From Fig 8.

(4) Initial value from items 8 and 9, Table 7 and consists of 255 gal C_4+ in the gas phase and 422 gal in the liquid phase. At one pore volume of injected gas the homogeneous permeability section has lost the 255 gal in the gas phase, added 78 × 0.19 = 15 gal from the injection gas giving a total of 437 which becomes distributed as 230 in the liquid phase and 207 gal in the gas phase.
Because the reservoir initially contains about 8 pct liquid, one pore volume is more than sufficient to displace all of the original reservoir gas at this pressure. The error in neglecting the amount of injection gas produced amounts to less than one gallon.

EFFECT OF INCOMPLETE COVERAGE OF RESERVOIR BY INJECTION GAS

Having evaluated the recovery from the portion of a reservoir which has been swept by injection gas, it becomes possible to evaluate the recovery from the complete reservoir. The macroscopic coverage can best be determined from electric model studies. For purposes of discussion calculations will be made for a macroscopic coverage of 75 pct.

Fig 13 shows the gross amount of C_4+ produced from a unit reservoir of 1000 cu ft of hydrocarbon space. The macroscopic coverage is 75 pct and the permeability variation is 0.55. The intercepts of the curves and the ordinate are the same as Fig 11. These intercepts represent the recovery obtained during pressure decline, and are independent of the macroscopic coverage and the permeability variation.

To illustrate the derivation of Fig 13 from Fig 11, consider the injection at 1310 psia and 195°F. of 100 Mcf into the unit reservoir. The injected volume will pass into and through 750 cu ft of reservoir hydrocarbon space, and will bypass the remaining 250 cu ft.

As the 100 Mcf of injection gas will effect only 750 cu ft of reservoir hydrocarbon space, the recovery from this volume will be equivalent to that obtained by passing 100 ÷ 0.75 = 133 Mcf through 1000 cu ft of "active" reservoir space. From Fig 11, the gross production will be 790 gal per 1000 cubic feet. Of this, 425 gal were produced during pressure decline, leaving a net of 365 gal per 1000 cubic feet which were produced due to injection. This is equivalent to 273 gal per 750 cubic feet. The total production for 75 pct macroscopic coverage, as

plotted in Fig 13, is 425 gal by pressure decline plus 273 by gas injection, or 698 gal C_4+ per unit reservoir. Fig 13 shows that for a particular amount of injected gas, the gross production of C_4+ is increased maintenance at 2960 psia will recover 71 pct of the C_4+ whereas pressure depletion to 400 psia followed by pressure maintenance at 400 psia will recover 87 pct of the C_4+.

TABLE 9—*Recovery of C_4+ by Pressure Maintenance at 1310 Psia*

Vol. of Injected Gas		C_4+ Content of Reservoir, Gal	Gallons of C_4+			Produced Gas, Mcf	Producing Ratio, Gal C_4+ per Mcf
Pore Vol	Mcf		Injected	Gross Prod.	Net Prod.		
1	2	3	4	5	6	7	8
0	0	677	0	0	0	0	3.2
0.2	16	629	3	51	51	16	3.2
0.4	31	581	6	102	102	32	3.2
0.6	47	538	9	148	147	48	3.1
0.8	62	495	12	194	192	63	3.0
1.0	78	451	15	241	237	79	2.8
1.5	118	356	22	342	333	120	2.08
2.0	156	294	30	413	397	159	1.60
2.5	195	254	37	460	438	198	1.25
3.0	234	217	45	505	475	238	1.02
4.0	312	159	59	577	532	318	0.76
5.0	390	119	74	632	573	396	0.61
6.0	468	82	89	684	610	476	0.50
8.0	624	53	119	743	639	635	0.32
10.0	780	34	148	791	658	793	0.22
15.0	1,170	22	222	877	670	1,183	0.20
20.0	1,560	15	296	958	677	1,573	0.19
∞		15			677		0.19

Notes on Calculation Methods

(2) Computed as shown in Table 8.
(3) From item 4, Table 8 and Table 5. For example, at 0.8 pore volume injected item 3 = $(0.36 \cdot 677) + (0.49 \cdot 437) + (0.13 \cdot 245) + (0.02 \cdot 70) = 495$.
(4) Injected gas contains 0.19 gal C_4+ per Mcf. Item 4 = 0.19 · item 2.
(5) Gross produced = original + injected − present content. Item 5 = 677 + item 4 − item 3.
(6) Net produced is the amount of the original rich gas produced and is equal to the gross produced minus the amount of injected gas that has been produced. The produced injected gas equals the pore volume injected − (1-fraction uneffected). Therefore, item 6 = item 5 − [(1) + (3, Table 6) − 1].
(7) At start of injection, 1000 cu ft of hydrocarbon space contains 38.5 lb-mols of liquid phase + 204 lb-mols of gas, (From Figs 1, 2, 3); total 242.5. After the hydrocarbon space contains only injected gas it will contain 208 lb-mols. Therefore, ultimately 242.5 − 208.0 lb-mols, or 13 Mcf, will be produced than have been injected. These 13 Mcf have been proportioned over the first ten pore volumes of injected gas.
(8) By graphical differentiation of items 6 and 7.

by declining the pressure before gas injection.

The calculations presented in Figs 11 and 13 are for the gross amount of C_4+ produced. Since the production includes some C_4+ originally present in the injection gas, Fig 14 is presented to show the percentage of the C_4+ originally in the reservoir which is produced. For an ultimate producing ratio of one gallon of C_4+ per Mcf of produced gas, pressure

CONCLUSIONS

The recovery of the heavier components from a gas cap or retrograde pool under various production methods has been calculated. The results show that the recovery is greatest if the reservoir pressure is allowed to decline prior to cycling dry gas.

ACKNOWLEDGMENTS

The authors are grateful to the management of the Standard Oil Company of

TABLE 10—*Recovery of* C_4+ *by Pressure Maintenance at* 860 *Psia*

Volume of Injected Gas		C_4+ Content of Reservoir, Gal	Gallons of C_4+			Produced Gas, Mcf	Producing Ratio, Gal C_4+ per Mcf
Pore Volume	Mcf		Injected	Gross Prod.	Net Prod.		
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
0	0	577	0	0	0	0	3.4
0.2	10	543	2	36	36	10	3.4
0.4	20	511	4	70	70	20	3.4
0.6	30	481	6	102	101	31	3.4
0.8	40	446	8	139	137	41	3.4
1.0	50	416	10	171	168	51	3.2
1.5	75	340	14	251	245	76	2.5
2.0	100	287	19	309	298	102	1.9
2.5	125	252	24	349	334	128	1.5
3.0	150	220	28	385	365	153	1.35
4.0	200	172	38	443	413	204	1.10
5.0	250	125	47	499	461	255	0.87
6.0	300	95	57	539	491	306	0.68
8.0	400	56	76	597	531	408	0.40
10.0	500	36	95	636	551	511	0.20
15.0	750	19	143	701	568	761	0.19
20.0	1,000	11	190	756	575	1,011	0.19
30.0	1,500	10	286	853	576	1,511	0.19
∞		10			577		0.19

See Table 9 for notes on calculation methods

TABLE 11—*Recovery of* C_4+ *by Pressure Maintenance at* 400 *Psia*

Vol. of Injected Gas		C_4+ Content of Reservoir, Gal	Gallons of C_4+			Produced Gas, Mcf	Producing Ratio, Gal C_4+ per Mcf
Pore Vol.	Mcf		Injected	Gross Prod.	Net Prod.		
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
0	0	463	0	0	0	0	4.6
0.2	4.4	445	0.8	18.8	18.8	4.8	4.6
0.4	8.8	427	1.7	37.7	37.7	9.7	4.6
0.6	13.2	410	2.5	55.5	55.5	14.6	4.5
0.8	17.6	390	3.3	76.3	76.0	19.5	4.4
1.0	22	371	4.2	96	95	24	4.1
1.5	33	329	6.2	140	138	36	3.5
2.0	44	287	8.4	184	180	49	3.0
2.5	55	259	10.5	214	208	61	2.6
3.0	66	234	12.5	242	233	73	2.4
4.0	88	187	17	293	280	96	1.9
5.0	110	143	21	341	324	122	1.6
6.0	132	110	25	378	357	146	1.4
8.0	176	68	33	428	399	195	1.0
10.0	220	43	42	462	425	243	0.80
15.0	330	23	62	502	443	353	0.40
20.0	440	10	84	537	457	463	0.25
30.0	660	5	125	583	462	683	0.20
50.0	1,100	4	208	667	462	1,123	0.19
100.0	2,200	4	418	867	463	2,223	0.19
∞		4			463		0.19

See Table 9 for notes on calculation methods

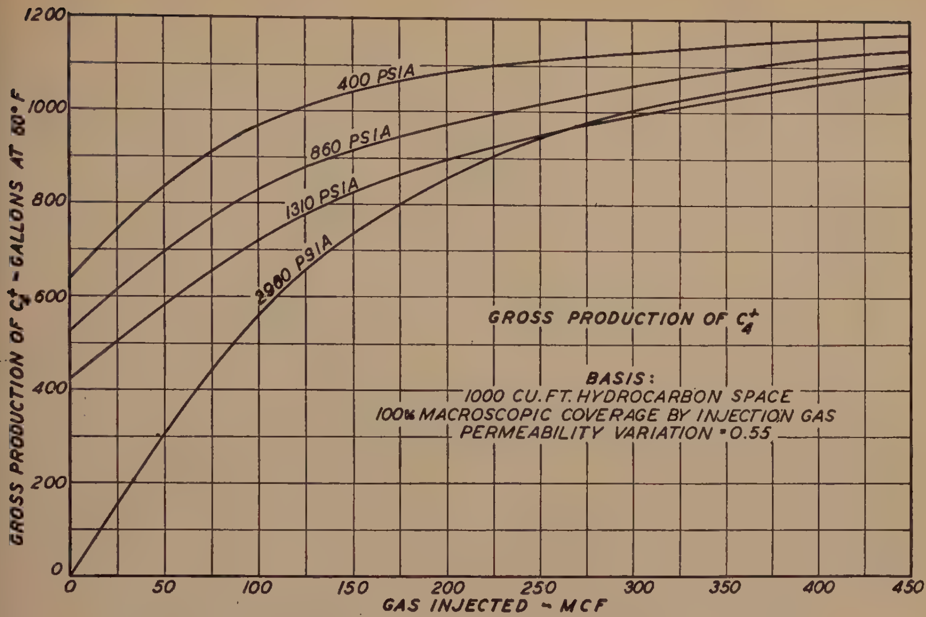

FIG 11—PRODUCTION OF C_4+ DURING CYCLING FROM A SAND SECTION.

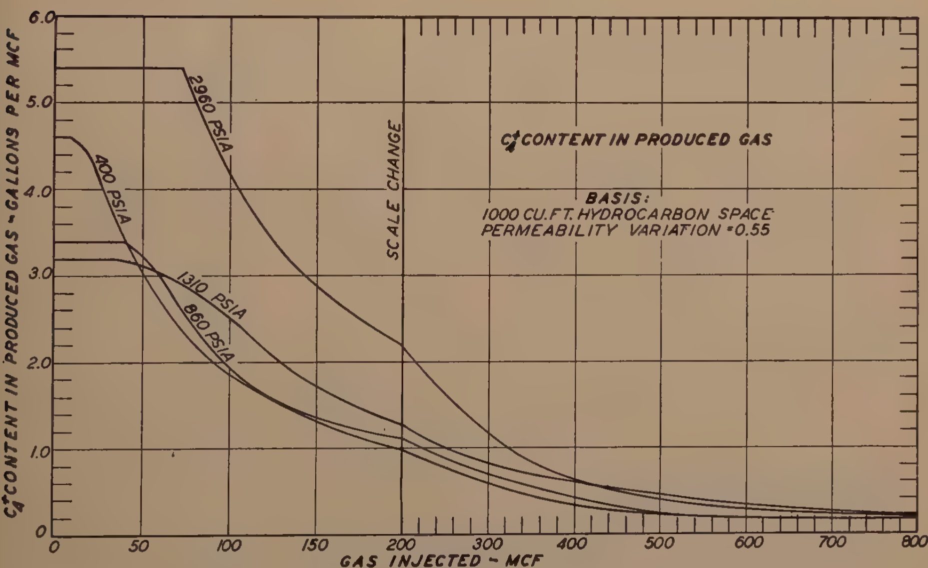

FIG 12—C_4+ CONTENT OF PRODUCED GAS FROM A SAND SECTION.

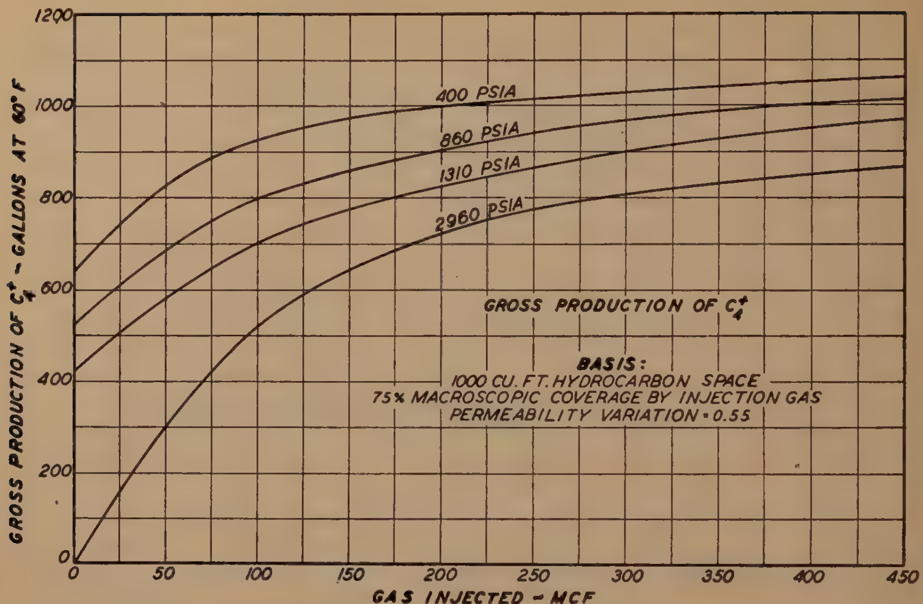

FIG 13—PRODUCTION OF C_4+ DURING CYCLING FROM A RESERVOIR.

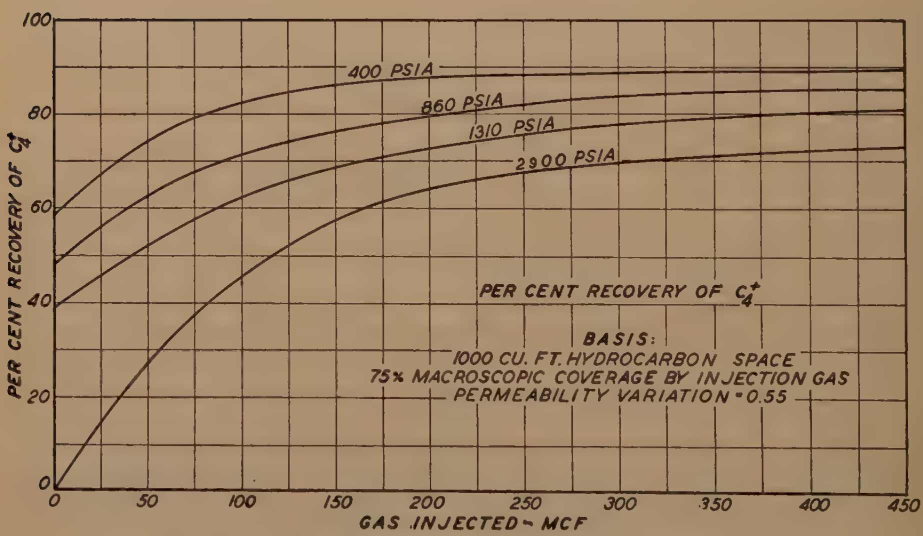

FIG 14—PER CENT RECOVERY OF C_4+ FROM A RESERVOIR.

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DISCUSSION

N. van Wingen*—The paper by Standing, Lindblad and Parsons is an important contribution toward a better understanding of the behavior of retrograde condensate-type reservoirs. The first essential prerequisite for an adequate prognostication of the behavior of such pools is the availability of variable composition (constant volume) PVT data such as presented here by the authors. This type of information has to date been very scarce as the majority of published research has dealt with systems of constant composition (variable volume). To the best of my knowledge only two variable composition papers have previously been published, one by E. W. McAllister[12] and the other by F. H. Dotterweich and E. O. Bennett.[13] Results obtained for constant as compared to variable-composition systems generally differ to a sufficient extent to be of significant economic importance. Thus, it is to be hoped that emphasis will be given in future research to this type of approach, rather than to additional work involving systems of constant composition which do not duplicate the behavior of actual reservoirs.

The authors' method of combining reservoir fluid thermodynamics with a consideration of the dynamic characteristics of the reservoir rock offers a unique approach to a difficult problem. It should be taken into account, however, that any calculations involving a consideration of permeability variation will be subject to a material potential hazards factor as data to adequately describe the permeability characteristics of a reservoir are seldom available. Jan Law[14] adequately demonstrated this point and concluded that current knowledge of fluid characteristics far outdistances knowledge of the interstitial characteristics of the sand phase. Thus, while the results of an analysis as here presented by Standing and co-authors is of considerable theoretical interest, the actual behavior of any field to which it may be applied may well differ markedly from that as indicated by the calculations. It is true that the authors point out an agreement between computations and results as obtained in a laboratory sand column, but this agreement resulted from the fact that, contrary to an actual reservoir, the permeable variation of the laboratory column was subject to accurate analysis. The authors' simplifying assumption of substituting for the actual variable permeability system one which is composed of layers each

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[12] E. W. McAllister: Application of Laboratory Data on Phase Behavior to Evaluation of Condensate Reservoirs. *California Oil World*, 2nd issue Oct. 1945.

[13] F. H. Dotterweich and E. O. Bennett: Trends in Processing Gas Condensate Reservoirs. *The Oil Weekly* (May 6, 1946).

[14] J. Law: A Statistical Approach to the Interstitial Characteristics of Sand Reservoirs. *Trans.* AIME (1944) **155**, 202.

of a constant permeability neglects the very important phenomenon of oblique flow. The combined effect of the above factors may be such that the coverage or recovery efficiency as actually obtained in a reservoir may, under certain adverse conditions, not even approximate that as here computed theoretically.

The above statements are not meant to detract in any sense from the value of this excellent paper, but rather to point out the extreme complexity and difficulty involved when field permeability data are to be used quantitatively. In this regard this paper again serves to bring out the desirability and ultimate economic value of conducting extensive coring and core analysis operations during the early stages of a field's development.

The authors' conclusion that for a variable permeability retrograde pool the recovery of heavier hydrocarbon fractions is greatest when the reservoir pressure is allowed to decline prior to cycling is of extreme interest. I do feel, however, that for any actual field certain other basic factors in addition to permeability variation should also be carefully considered before proceeding to deliberately reduce the initial reservoir pressure. Thus for example, all California condensate pools discovered to date have been found to be underlain by black oil production. For the majority of such reservoirs the increased black oil recovery obtainable from a maintenance of gas cap pressure should in general far outweigh economically the value of the decreased butane plus recovery for the gas cap. Also irregular by-passing can probably be controlled more effectively at the higher pressures.

I would like to ask the authors the following questions:

1. To what extent would a 50 pct error in the concept of a field's permeability variation (which is well conceivable) effect the theoretically computed butane plus recovery.

2. The authors have varied nearly all the parameters except composition. What would be the effect on the analysis if the gas were either very much richer or leaner than the one here considered.

3. The authors cite a recovery of butane plus of 71 pct for pressure maintenance at 2960 psi as compared to 87 pct for depletion to 400 psi followed by cycling at the latter pressure. Rather than merely considering the respective quantities of butane plus, what would be the respective values of the total products recovered for the two methods of operation.

4. Is it possible that errors in the calculation due to lack of adequate basic data may effect the final result to an extent greater than the theoretically computed increased recovery. In other words, what is the probable degree of certainty of the theoretically computed increased recovery at the lower pressure.

J. C. Young*—In Figs 13 and 14, which show the relationship of the recovery of C_4+ versus the amount of gas injected, did you include in your calculation the C_4+ which can be produced after each method of cycling is completed and the reservoir is being depleted down to a minimum pressure without gas injection?

If not, it appears to me that a considerably higher ultimate recovery of C_4+ can be expected from the 2960 psia-cycling system than shown. After cycling at 2960 psia, according to your calculation for an ultimate producing ratio of one gallon of C_4+ per Mcf of produced gas, there is left in the formation 29 pct of the original C_4+. Table 7 shows that there is 58 pct of C_4+ produced by pressure decline from the dew point to 400 psia. If this is so, with the remaining C_4+ in the formation, then the ultimate C_4+ recovered can be expected to be in the neighborhood of 88 pct when the reservoir is totally depleted.

Can you give me the recovery of C_4+ expected by pressure decline to 400 psia after each method of cycling to a producing ratio of one gallon of C_4+ per Mcf of produced gas?

In regard to the behavior of the reservoir fluids during dry gas-injection, you assume that no mixing takes place between the injected gas and the reservoir gas. Will you please give me some of your reasons for this assumption? Undoubtedly, you have laboratory data to verify it.

I wish to take this opportunity to compliment you and the co-authors of this excellent paper. It is a great contribution to the industry. It has introduced invaluable data which

* Conservation Committee of California Oil Producers, Los Angeles, California.

engineers can use in the determination of the most economical method of producing condensate or large gas-cap fields.

E. C. Babson*—Messrs. Standing, Lindblad and Parsons have presented a radical departure from the conventional concept of the mechanics of cycling. In the past, most writers on the subject have assumed, either implicitly or explicitly, that the principal gain in recovery resulting from cycling is due to the production of a considerable portion of the hydrocarbons from the reservoir before the pressure has declined to a level which would permit appreciable retrograde condensation. It has been considered that for practical purposes no important portion of the hydrocarbons which have condensed in the reservoir can be recovered by revaporization. Mr. Standing and his collaborators present quite a convincing case that this point of view is in error and that the vaporization of hydrocarbons condensed in the formation can be of great importance.

Table 12—*Permeability Variation in California Oil Sands*

Field	Zone	Phi Standard Deviation	Permeability Variation
Dominguez	Second	1.9	0.48
	Third	2.4	0.57
	Fifth	2.3	0.55
East Coyote	Second	3.2	0.67
	Second and Third	3.1	0.66
	Stern	5.4	0.85
Olinda	Miocene	1.9	0.48
	Miocene	4.2	0.77
	Miocene	3.5	0.70
	Miocene	3.7	0.72
	Miocene	3.0	0.65
	Miocene	2.3	0.55
	Miocene	4.4	0.73
Richfield	Chapman	2.1	0.52
Rio Bravo	Rio Bravo	1.0	0.30
	Rio Bravo	1.1	0.32
Rosecrans	Lower Zins	1.8	0.47
	Lower Zins	2.6	0.60
	Lower Zins	2.3	0.55
	O'Dea	2.7	0.61
	O'Dea	2.3	0.55
	O'Dea	2.0	0.50
	O'Dea	2.8	0.62
	O'Dea	3.2	0.67
	O'Dea	2.0	0.50
Santa Fe Springs	Bell (Composite)	2.4	0.57
	Meyer	2.1	0.52
	Nordstrom	2.2	0.54
	Nordstrom	1.0	0.30
	Buckbee	1.7	0.45
	Buckbee	2.1	0.52
	O'Connell	1.2	0.34

There is one weakness in the authors' approach which could possibly modify their results significantly. The authors' calculations are all based upon equilibrium conditions and their conclusions would certainly be applicable to an operation in which sufficient time were permitted for the injected gas to come to equilibrium with the condensed liquid in the formation. The question arises, however, whether the speed of vaporization is rapid enough to permit a close approach to equilibrium during an actual cycling operation.

The author's Table 3 is of interest, particularly in the light of recently published statements regarding the extreme variation in permeability in California oil sands. In order to amplify the information given by the author, some additional data on permeability variation in California oil sands are shown in Table 12.

* Union Oil Co., Santa Fe Springs, California.

W. T. Lietz*—The authors calculate, under the circumstances outlined in the report, pressure maintenance at 2960 psi will lead to an ultimate recovery of 71 pct of the C_4+ originally present in the sand; whereas, depletion to 400 psi, followed by pressure maintenance at that reduced pressure, will bring this recovery up to 87 pct.

In the first case, however, after hoving recovered the 71 pct, the reservoir has still the original pressure and with the subsequent depletion, additional liquid products will be recovered. In the second case, this final depletion will yield a substantially smaller amount of additional oil because, firstly, more C_4+ has already been recovered and, secondly less gas is available to carry off the C_4+ fractions.

It would be interesting to see the calculations carried on beyond the end of pressure maintenance and obtain a recovery efficiency for a final pressure of, say 200 psi for the two operating schemes discussed in the paper.

Finally, a comparison of costs for the two methods would add to the value of this paper.

M. B. Standing, E. N. Lindblad and R. L. Parsons (authors' reply)—Much of the

* Shell Oil Co., Los Angeles, California.

comment on the paper has been focused on the possibility of obtaining recovery by pressure decline after cycling to economic depletion at the dew point. The following discussion covers this point, and answers in a general way the comments of Messrs. W. Tempelaar Lietz, N. van Wingen, and J. C. Young.

After cycling to depletion at the dew point, the reservoir may be divided into two regional volumes: a volume containing essentially original dew-point material and a larger volume containing a mixture of original dew-point material and dry injected gas. In the larger volume, the dew-point material may be thought of as being in the lower permeability parts, although a considerable amount of mixing will probably have taken place.

The production by pressure depletion from this reservoir will be a mixture of the production from the two regional volumes. As an approximation, the rates of production from the two regional volumes will be in proportion to their volume. By further assuming normal retrograde behavior in the region containing original reservoir gas, and no retrograde behavior in the region containing predominantly dry injected-gas, the curves of Fig 15 may be calculated. The results show that if the butanes-plus content of production from the original reservoir gas is more than four times the butanes-plus content of gas that may be processed economically, additional butanes-plus may be economically recovered by declining the pressure after cycling to

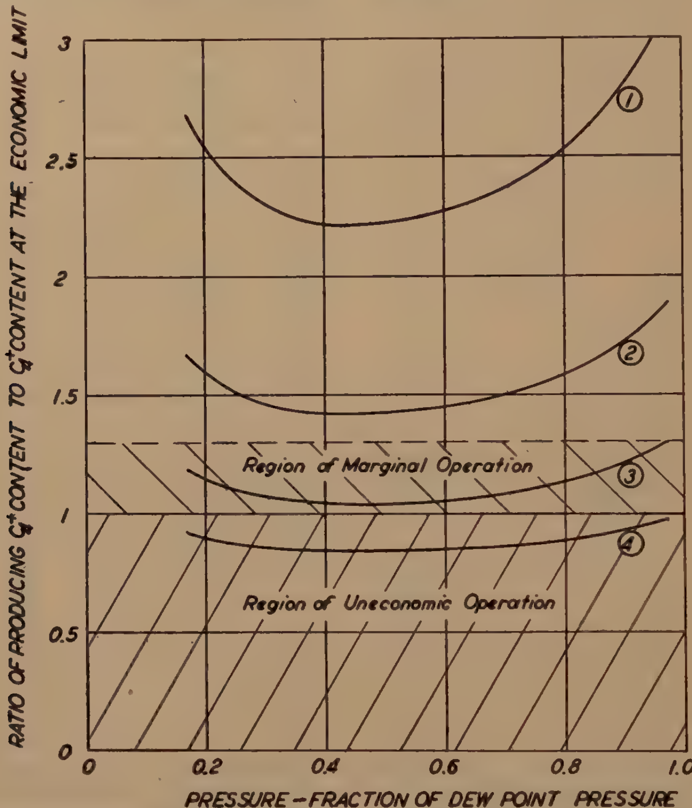

FIG 15—CHART SHOWING RATE OF PRODUCTION OF BUTANES PLUS DURING PRESSURE DECLINE AFTER CYCLING TO DEPLETION AT DEW POINT.

Permeability variation = 0.55 Macroscopic coverage = 75 pct

Curves are for systems of constant original composition: 1. Original producing ratio of 10 times economic limit; 2. Ratio of 5.4; 3. Ratio of 3; 4. Ratio of 1.5.

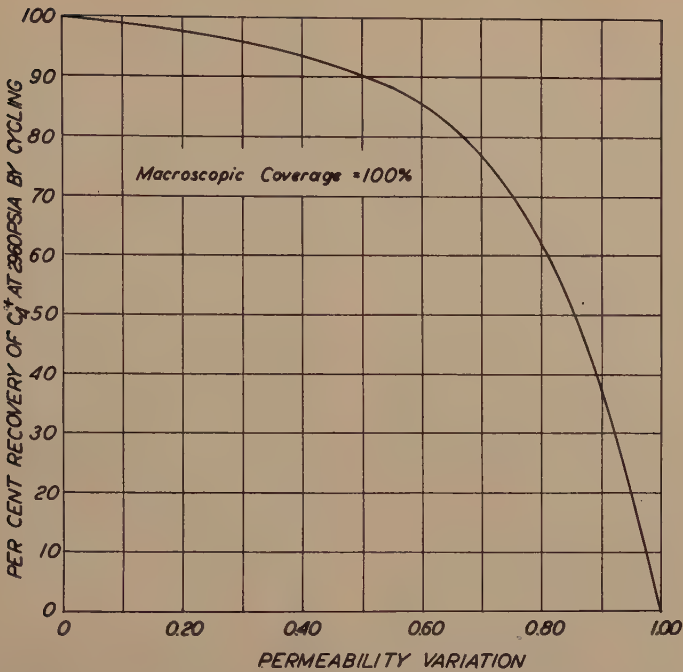

FIG 16—RECOVERY OF BUTANES PLUS BY CYCLING AT DEW POINT FROM PORTIONS OF RESERVOIR SWEPT BY INJECTED GAS.

Original producing ratio is 5.40 gal per Mcf. Final producing ratio is 1.00 gal per Mcf.

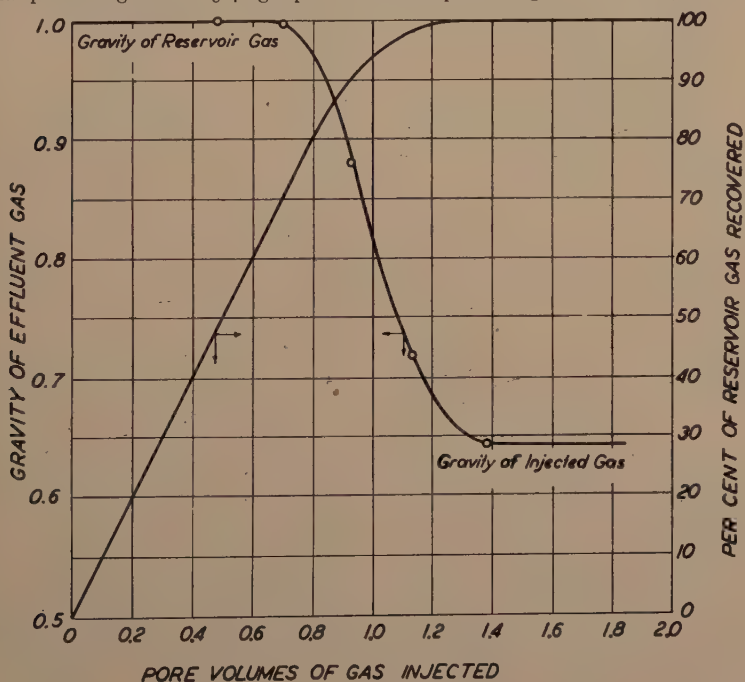

FIG 17—EXPERIMENTAL DATA SHOWING EFFICIENCY WITH WHICH ONE GAS IS DISPLACED BY SECOND GAS IN SAND SECTION OF CONSTANT PERMEABILITY.

depletion at the dew point. Additional results, not shown graphically, indicate that the recovery of the butanes-plus for the richer mixtures (more than a ratio of 4) is the same for cycling at the dew point followed by pressure decline to a low pressure as for initial pressure decline to a low pressure followed by cycling to depletion. In both cases, the heavier fractions remaining in the reservoir at depletion are very nearly equal to the heavier fractions existing in the macroscopically by-passed region after straight pressure decline. All of the above conclusions have been based on the experimental results obtained with the particular retrograde mixture used in this study. However, it appears likely that the conclusions are broad enough to be applicable to any retrograde mixture, and this is the justification for presenting the results in dimensionless form.

To summarize, additional recovery may be had by pressure decline after cycling to depletion, providing the original retrograde mixture is sufficiently rich. For rich mixtures the recovery is independent of the cycling pressure and the problem reduces to that of determining the most economical pressure at which to cycle. For lean mixtures, the maximum recovery is obtained if cycling is preceded by pressure depletion.

With respect to the question by Mr. Van Wingen on the effect of an incorrect evaluation of the permeability variation, the effect may be determined by calculating the recovery for several different permeability variations. This has not been done. However, as an indication of the results which would be expected, the recovery for cycling at the dew point has been calculated for several different permeability variations. The results are shown in Fig 16. These results indicate that if the permeability variation is low, say less than 0.60, the percentage of recovery is relatively independent of the variation.

Mr. Young's questioning of the flooding efficiency in a section of uniform permeability is in order. The displacement efficiency of one gas by another in a section of constant permeability was assumed in the calculations to be 100 pct. This assumption was based on an experimental test in which air was displaced by a dry hydrocarbon gas from a tube packed with unconsolidated sand. The results of the test are shown in Fig 17. The results show that after the injection of one pore volume of gas, 94 pct of the air has been displaced.

Mr. Babson's data on the permeability variation of several California sands are appreciated. The data show that for the sands considered, the permeability variation in California is certainly no greater than in other parts of the country. The permeability variation of the Chapman zone as determined by Mr. Babson (0.52) and by us (0.58) indicates the extent to which two computers might differ in estimating the variation in a sand.

Some Aspects of High Pressures in the D-7 Zone of the Ventura Avenue Field

By E. V. Watts,* Junior Member AIME

(Los Angeles Meeting, October 1946)

Abstract

The D-7 zone of the Ventura Avenue field is of special interest because the initial reservoir pressure at 9200 ft nearly equaled the pressure exerted by the overburden. While the phenomenon has been observed elsewhere in the world, there is no record of a previous case in California. Such high pressures have been attributed to sealing of the reservoir, followed either by emergence of the beds or by compaction of the sediments in various ways. Oil in the D-7 zone is undersaturated. At pressures above the bubble point, oil is recovered by the slight expansibility of the reservoir framework and its liquid contents. More than 40 pct as much oil probably will be recovered by this mechanism as will be recovered by internal gas drive after pressures pass below the bubble point. Operations are handicapped by sand and pipe troubles.

Introduction

The Ventura Avenue field has been under development since 1915. It has long been considered a "high-pressure" field, but interest was heightened by the extreme conditions encountered in the recent development of the so-called D-7 zone. The original reservoir pressure in this pool is estimated to have been 8300 psi at a depth of 9000 ft below sea level, or 9200 ± ft below the surface.

A fluid pressure approaching that exerted by the overlying sediments has been encountered in other parts of the world, but never before in California to the degree observed in the D-7 pool. With few exceptions, the original pressure in California fields is about equivalent to the static head of water below the water table in the outcrop.

Structure

The Ventura anticline is a prominent feature of the Ventura basin, being traceable on the surface about 17 miles.[1] The Ventura Avenue field is at the apex of the anticline. It is about one mile wide and five miles long, the major axis lying in an east-west direction. The productive limits cover an area of about 2300 acres.

The entire anticline has been severely folded and faulted. The productive portions in particular are broken up by three major thrust faults having a general east-west strike. The resultant four fault blocks are termed the A, B, C, and D blocks, respectively. Certain electric-log intervals are assigned numbers. Fig 1 is a diagrammatic north-south section of the field near the crest, looking west, and shows three of the four fault blocks. To the west, the upper fault divides into two branches, which define the B block.

Wells penetrating a fault may duplicate over 1000 ft of formation. However, the greater fault movement is the strike shift, which is believed to exceed 2500 ft both between the A and C blocks and between the C and D blocks.

The location of water is irregular and unpredictable. A few intermediate waters exist, while some strata have more than 2000 ft of productive closure.

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[1] References are at the end of the paper.

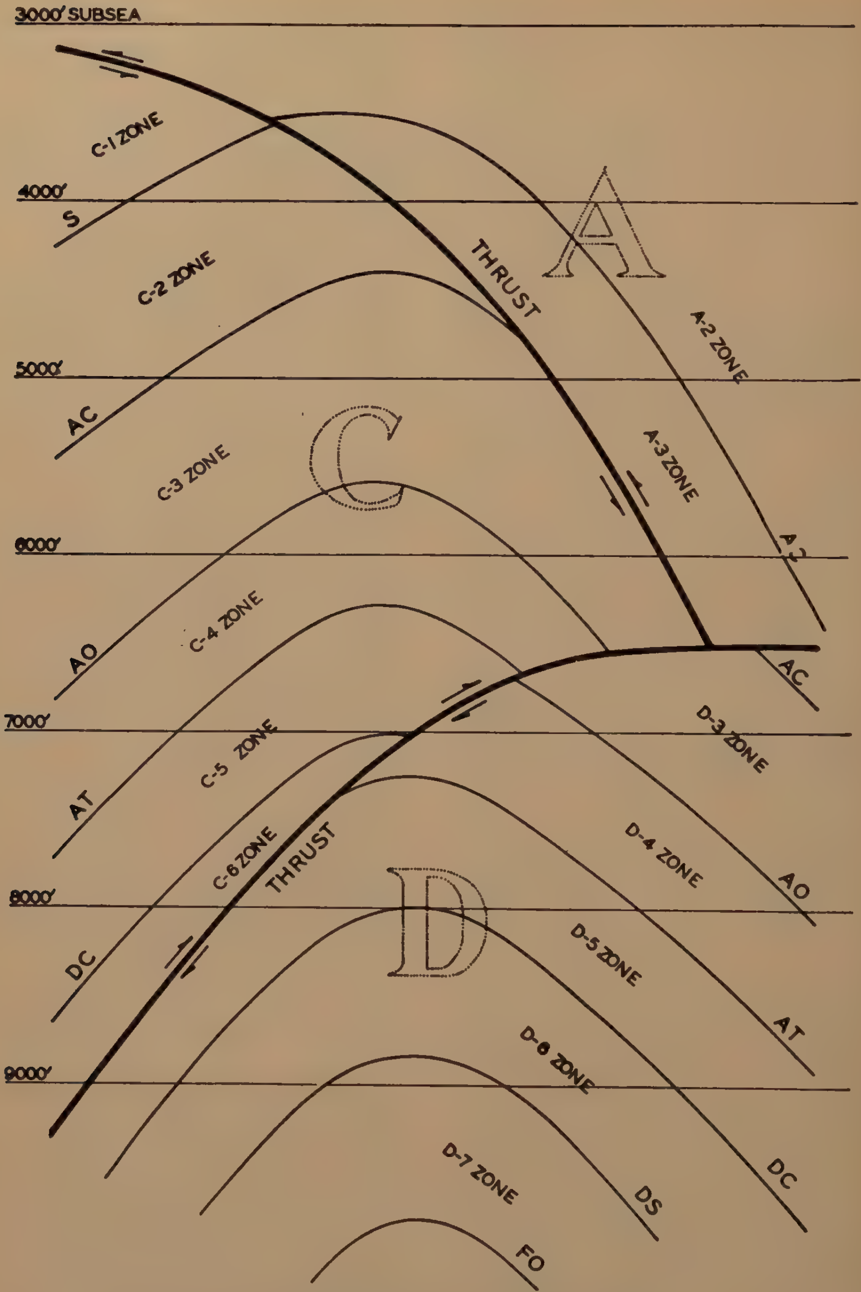

FIG 1—CROSS SECTION OF VENTURA AVENUE FIELD.

The principal oil accumulations are below 3000 ft subsea. As shown by Fig 1, the D-7 zone exists at depths below 9000 ft and is stratigraphically the deepest zone yet developed. Active drilling of the zone commenced in late 1943. As of Aug. 1, 1946 thirty wells were producing a total of 13,000 bbl per day of 32° to 33° API oil, 11,700 Mcf of gas, and 450 bbl per day water. Cumulative oil recovery to this time was slightly over 7½ million barrels.

All sediments penetrated to date consist of alternating sands and shales of Pliocene age. The surface beds are of the Pico formation, while the AK electric-log marker (not shown on Fig 1) is considered by some to be the top of the Repetto. The depth to the top of the Miocene is unknown, but may be more than 500 ft below any well drilled to date.

Pressure-depth Relationship

One conception of the original pressure-depth relationship for the Ventura Avenue field (Fig 2) shows that 7000 to 9500 ft is a region of rapid transition from pressures several hundred pounds per square inch in excess of hydrostatic to pressures several hundred pounds per square inch less than geostatic. The hydrostatic gradient is here considered to be 0.44 psi per foot, while the geostatic gradient is placed at the commonly accepted 1.0 psi per foot.

Inasmuch as a "zone" consists of several sand members, all of which usually are open to production simultaneously, it is impossible to establish precisely the pressure in any particular member. Properly speaking, the depth-pressure relationship of Fig 2 no doubt ascends as a series of finite increments. Pressures below the D-7 zone are conjectural.

High Pressures in Other Areas

One of the earliest references to fluid pressures near the geostatic is found in Keep and Ward's description of drilling problems in the Khaur field of India.[2] After mud weights of 150 to 160 lb per cubic foot proved unsatisfactory, pressure drilling was resorted to. From the mud weights and surface pressures then required, it was reliably established that the formation pressure was 5060 psi at 5215 ft and 5420 psi at 5478 ft.

In 1937 Abraham implied that similar pressure conditions had been encountered in Burma.[3] Without elaboration, Colvill mentioned use of 100-lb muds with 600 to 1100 psi surface pressure to control water in an 8000-ft well in Iran.[4]

In 1938 Cannon and Craze presented the relation of pressure to depth in the Gulf Coast region of Texas and Louisiana.[5] Subsequent observations in the Gulf Coast area were included in a 1946 paper by Cannon and Sullins.[6] Maximum abnormal pressures in pounds per square inch were 0.9 times the depth in feet, and were found at depths below 9500 ft. The authors also reported that abnormal pressures have been encountered in North Louisiana and East and West Texas.

Oil fields in Trinidad are reported to have pressures up to 0.8 psi per foot below the surface.[7] The depth at which such pressures are found was not specified, but probably is less than 6000 ft.

In the Rocky Mountain area, publicity was given a gas well completed during 1946 in southwestern Wyoming at a depth of 12,892 ft. The shut-in surface pressure was 5600 psi. Assuming a gas gravity of 0.65, a formation pressure of 7800 psi is indicated.

As previously mentioned, pressures in excess of hydrostatic are encountered infrequently in California. One noteworthy case is the high-head water sands in the Temblor formation of the Lost Hills field. At a depth of 4400 ft, a mud weight of 103 psi resulted in strong water flow, while 108-psi mud resulted in lost circulation. Indicated pressure at this depth therefore is 3200 psi.

With the exception of Trinidad and

Burma, these cases are all summarized on Fig 2. These instances demonstrate that so-called "abnormal" or "excessive" pressures are not peculiar to any one part of the world. While the bulk of the information readily available has been cited, many other instances probably exist that have not been widely publicized.

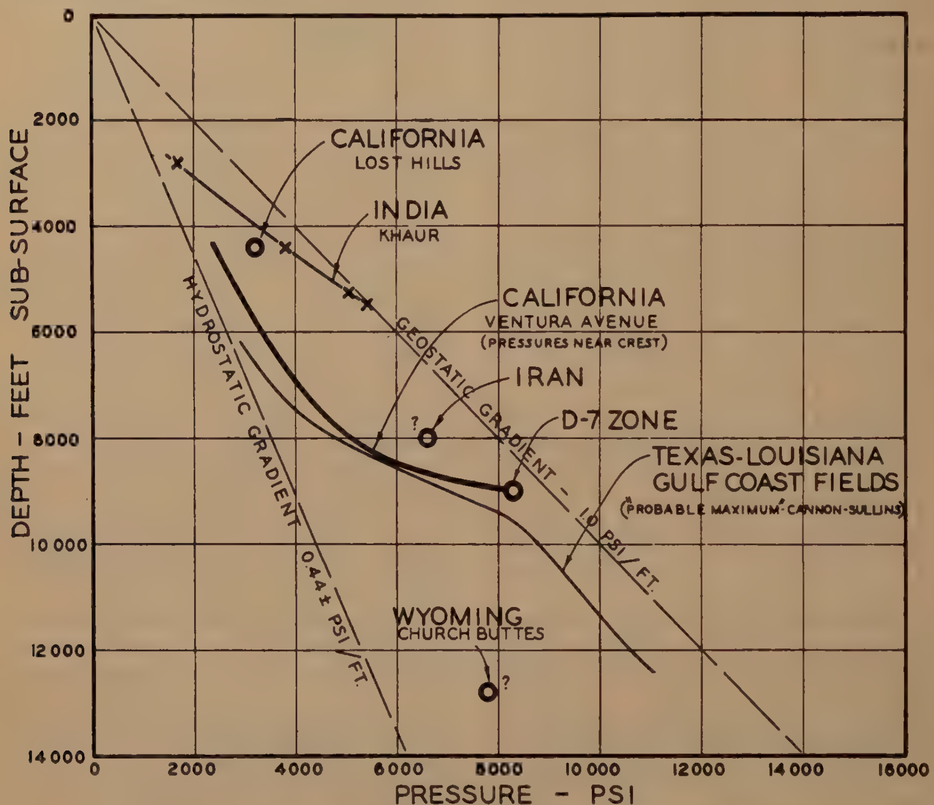

Fig 2—Depth-pressure relationship in high-pressure areas.

Cause of High Pressures

Various hypotheses have been advanced to account for the generation of high pressures that cannot be explained by existing hydrostatic heads. Regardless of which hypothesis seems most plausible, it is evident that any reservoir in question is effectively isolated from surrounding strata. As Cannon and Sullins expressed it, "The seal against escape of this pressure may be caused either by deposition, or faulting. The conclusion that there must be a seal to trap the high pressure seems inescapable; otherwise, the pressure would be dissipated to the outcrop or into zones of normal pressure and thence to the outcrop."

At Ventura, the nature of the structure suggests that faulting has caused the seal. There is nothing in the chemical character of the waters now found in the formation to indicate that secondary deposition is the cause.

As to the generation of high pressures in reservoirs after the seal has been effected, the following explanations deserve critical consideration:

1. *The sandstone of the reservoir is incompetent to support overburden.* Lacking an escape, the fluids are compressed as the formation compacts.

Theories related to the strength of sandstones are difficult to prove or disprove because of the dearth of applicable data on sandstone behavior. Investigators have more often been interested in the properties of rock under the enormous pressures that exist deep within the earth. Relatively few studies have been made of sandstones at moderate pressures.*

Because different sandstones have been tested under different methods of loading, few generalizations can be made. For example, Carpenter and Spencer studied the behavior of consolidated Texas cores enclosed in thin metallic jackets and subjected to external fluid pressures up to 8000 psi.[8] The change in pore volume, as measured by the volume of liquid expelled, averaged about 3×10^{-6} volumes per unit volume per pound per square inch. The stress-strain relationship was largely reversible. On the other hand, Grant reports that experiments on certain consolidated California sandstones showed the stress-strain relationship to be but slightly reversible and greatly affected by the duration of load.[10] In these particular experiments, cores were placed in heavy steel sleeves with steel plugs at either end, then subjected to longitudinal forces applied through the plugs. The compressibilities varied widely but all were at least several times greater than the values found by Carpenter and Spencer. Such widely variant results indicate the necessity of studying sandstones from the particular field in question.

In the generation of high pressures, an important point is whether or not sandstone has an elastic limit in the true sense of the word; i.e., the ability to withstand a finite stress indefinitely and without increasing strain. If sandstone does possess an elastic limit, it will always carry a corresponding portion of the weight of the overburden. As a consequence, a fluid pressure very nearly equal to the weight of the overburden cannot be developed by mere compaction.

On the other hand, properties observed in the laboratory over a short space of time may not reflect the behavior of the material over geologic time. "Creep" has been observed in many substances. The movement of glacier ice is tangible evidence that crystalline solids can flow. Deep mines experience movements of seemingly solid rock, which suggests a sort of viscous flow. However, these materials are compact crystalline aggregates in which movement is generally attributed to recrystallization, or the rearrangement of atoms to form new shapes.

The work of Griggs showed that the strain of certain materials after applying a constant compressive stress below the so-called elastic limit can be expressed as

$$\text{Strain} = A + B \log t + Ct$$

where A, B, and C are constants and t is time.[11] A represents the initial strain, $B \log t$ represents elastic flow, while Ct is the pseudoviscous flow. On release of the stress, the strain becomes

$$\text{Strain} = A' - B \log t$$

Unfortunately, Griggs did not investigate sandstone specifically. For some materials such as limestone, the coefficient C is zero, B relatively small. Of course the semilogarithmic relation may not hold indefinitely, but it is interesting to note that a fourfold extrapolation of several hundred days' measurements indicate that elastic flow of the limestone investigated would amount to only 0.2 pct in a million years.

*Bibliographies of references 8 and 9 will be useful to those who wish to review existing experimental data.

As for practical evidence, the lack of a general correlation of porosity of sandstones with their age suggests that creep has not proceeded at a material rate with time. On the other hand, deep wells sometimes encounter abnormally low porosity at great depth—a fact that indicates that sandstones may be compacted, at least under the usual conditions in which fluid pressure supports only the smaller portion of the overburden weight. This leads to speculation as to how much porosity and permeability will be found in very deep reservoirs when economic conditions permit drilling for them.

In the Ventura field, the strata withstood the compacting effort of a much greater depth of burial before the D-7 zone was sealed. The Ventura basin has perhaps the thickest marine Pliocene sediments in the world—an estimated 15,400 ft in the vicinity of the anticline.[12,13] Quaternary sediments total 3000 ft, but since the uplift is believed to have commenced in the beginning of Pleistocene time, the Pliocene may never have been covered. Assuming the base of the Pliocene to be 500 ft below the base of the D-7 zone, the latter may have once been at 14,900 ft, or about 5500 ft below the present depth.

2. *Abnormal pressures are inherited or "fossil" pressures,* remaining from an age when the reservoir was sealed at greater depth. Presumably the pressure was normal for the original depth of the accumulation; the reservoir was then sealed, after which it was elevated to the present depth.

For example, a reservoir originally at 10,000 ft would have a normal pressure of, say, 4400 psi. If it were then sealed off and raised to 4400 ft, the pressure, if unchanged, would equal the new weight of the overburden; that is, the initial depth must be more than twice the present depth.

This explanation was rejected for the Khaur and Gulf Coast fields because the accumulations were never sufficiently deep. The same reason also applies to the Ventura field. From the features of the Ventura basin discussed above, it is unlikely that the D-7 pool was ever as much as 20,000 ft deep.

Even if the strata had been considerably deeper than indicated, the hypothesis is invalid if the uplift is accompanied by an appropriate reduction in temperature. Owing to thermal contraction, the pressure of confined fluids decreases rapidly with decreasing temperature. If it is assumed that the pore volume contains 40 pct water and 60 pct oil, calculations using the coefficients of Table 1 indicate that if the beds cool only 0.85°F per 100 ft in moving toward the surface, the pressure will remain "normal:"

TABLE 1—*Data for Calculations*

Data	Oil	Water	Sandstone
Coefficient of thermal expansion, volumes per volume per deg F	7.0×10^{-4}	3.3×10^{-4}	0.18×10^{-4}
Compressibility, volumes per volume per psi	-13×10^{-6}	-2.7×10^{-6}	1.4×10^{-6}[a]

[a] Net change in pore volume due to change in unbalanced weight of overburden less bulk volume change of sand grains. Obtained by modification of Carpenter and Spencer's data.

Let α = coefficient of thermal expansion, volumes per unit volume per degree Fahrenheit

β = compressibility, volumes per unit volume per pound per square inch

f = fraction of pore volume occupied by fluid

Δt = change in temperature, degrees Fahrenheit per foot

Δp = change in pressure, psi per foot

Δh = change in depth, feet

Subscripts w, o, and s refer to water, hydrocarbons, and sandstone, respectively equating changes in liquid volume to changes in pore volume:

$$(f_o \alpha_o + f_w \alpha_w) \frac{\Delta t}{\Delta h} + (f_o \beta_o + f_w \beta_w) \frac{\Delta p}{\Delta h} = \alpha_s \frac{\Delta t}{\Delta h} + \beta_s \frac{\Delta p}{\Delta h},$$

or
$$\frac{\Delta p}{\Delta h} = -\frac{(f_o \alpha_o + f_w \alpha_w - \alpha_s)}{(f_o \beta_o + f_w \beta_w - \beta_s)} \times \frac{\Delta t}{\Delta h}.$$

Substituting values from Table 1 and letting $f_o = 0.60$, $f_w = 0.40$

$$\frac{\Delta p}{\Delta h} = 52 \times \frac{\Delta t}{\Delta h}.$$

That is $\frac{\Delta p}{\Delta h} > 0.44$ psi per foot when $\frac{\Delta t}{\Delta h} > 0.85°F$ per 100 ft. Expansion of the reservoir framework due to degradation at the surface will further reduce the reservoir pressure slightly. Although the geothermal gradient may have varied through the ages, it now exceeds 1.4°F per 100 ft in California sediments.[14]

3. *Tectonic forces compact sediments laterally.* A drawback of the hypothesis that tectonic forces compact the sediments laterally is that it cannot be consistently applied to all reservoirs; for example, some of the high pressures in the Gulf Coast area occur in domes wherein the faulting is normal and the chief tendency is toward elongation of the sediments. Such faults would provide a seal, but the excessive pressure would have to be created by some mechanism other than lateral compaction.

As for structures in which the stresses are compressive, any appraisal is again hampered by the lack of information on the stress-strain behavior of sandstone. Even if the properties were known, the complex, redundant loading of the actual structure would make an analysis difficult. For the hypothesis to be valid, sandstones must resist fracture under compacting forces great enough to generate the geostatic pressure. Theoretically the condition could most likely be fulfilled in a unit cube of sandstone subjected to the weight of the overburden vertically and to two equal compacting forces at right angles horizontally. From a conventional stress analysis of this system, it is problematical whether or not sandstones possess the necessary strength; that is, the formation may fail in shear before a geostatic pressure can be developed. The explanation lies in the fact that even well consolidated sandstone is relatively weak unless it is confined. In the present case the only restraint is that offered by the unbalanced weight of the overburden, which diminishes as the pressure increases.

If an actual reservoir does possess the necessary strength, or enough elasticity relative to the fluid contents, there is no reason why the compaction may not proceed past the point at which the fluid pressure equals that of the overburden. The formation would then be parted by the pressure, with the overlying strata supported solely by the liquid. It would therefore be possible to produce fluid at substantially constant pressure until the strata had settled to their original position. So far as is known, this whimsical situation has never developed.

4. *Under the weight of the overburden, water is gradually expressed from shales interbedded with the sandstone.* Having no escape, the fluids in time assume a pressure exactly equal to the overburden.

This hypothesis is the one most difficult to refute. The transition of soft clays to dense shales is accomplished chiefly by the squeezing out of interstitial water, a process that proceeds with astonishing slowness. For example, Athy demonstrated that an exponential relationship exists to the present day between average porosity and depth of certain shales in

Oklahoma of Permian and Pennsylvanian age.[15] His average values were:

Depth of Burial, Ft	Average Porosity, Pct
2,000	20
3,000	13
4,000	8
5,000	5½
6,000	3½
7,000	2

Thus, after several hundred million years the shallower shales still retain significant percentages of water.

The reported instances of abnormal pressures previously discussed occur for the most part in young sediments. The ages of the beds penetrated by the Iranian well were not reported. The Wyoming case is in an upper Cretaceous formation, but the remainder are all in Tertiary beds. Assuming the seal of these reservoirs was effected in Pleistocene time, it is easy to conceive of their shales still containing enough water for the subsequent generation of higher pressures. Studies of Ventura Avenue shales have not been completed, but as an indication of the amount of water still remaining in D-7 shales, several samples averaged 16 pct.

To summarize: four possible mechanisms explaining the origin of geostatic pressures have been discussed. Any one or a combination of several could account for abnormal pressure in a particular case. However,

1. The first hypothesis relating to vertical compaction of sandstone is not applicable to structures that are emergent unless behavior is affected by "creep," a subject on which few data are available.

2. The second hypothesis, concerning emergence, is seldom applicable and probably can be discarded.

3. The third hypothesis, relating to horizontal compaction, is applicable only in compressive systems and is again attended by the uncertainties of sandstone behavior.

4. The fourth hypothesis, that dealing with the expression of fluids from shales, is applicable generally and is tendered as the most likely mechanism in the case of the D-7 zone.

Reservoir Behavior

Older zones in the Ventura field are characterized by dissolved gas drive, or depletion-type recovery. Little natural water encroachment is evidenced. Since it is likely that the D-7 zone is sealed in the vicinity of the field, the chances for a water drive seem even more remote.

The bubble-point pressure in the D-7 zone is estimated to be 3500 psi. Between the initial pressure and the bubble point, oil can be recovered only by virtue of the slight expansibility of the reservoir and its liquid contents. Contrary to general opinion, this phase of the recovery process is a significant portion of the total. If the experience in the older zones is any criterion, the D-7 may be ultimately depleted to a gas saturation of about 22 pct. Using 17 pct porosity, 40 pct interstitial water, 1.45 bubble-point formation-volume factor, and 1.15 final formation-volume factor, the gas-expansion recovery is calculated to be 110 bbl of tank oil per acre-foot of productive sand.

However, by application of the data in Table 1, it is calculated that recovery above the bubble point, due to the net volume change of the reservoir and the contained liquids, amounts to 13.5 bbl of reservoir fluid per acre-foot per 1000 psi change in pressure. At an average formation-volume factor of 1.42, the drop in mean formation pressure from 8500 psi to the bubble point of 3500 psi would therefore be accompanied by the production of about 47 bbl of tank oil per acre-foot. The distribution of this recovery as to source is shown in Table 2. Presumably these volume changes are all reflected in the production of oil rather than water, the change in relative permeability to interstitial water being insignificant.

TABLE 2—*Distribution of Recovery by Source*

Source of Recovery	Subsurface Volume of Fluid Expelled, Bbl per Acre-ft per 1000 Psi	Total Bbl Tank Oil Produced per Acre-ft for 5,000 Psi Change at Average Formation Volume Factor of 1.42
Expansion of oil	10.3	36
Expansion of water	1.4	5
Contraction of pore volume	1.8	6
Total	13.5	47

Expressed in another way, the "excessive" pressure should result in an ultimate acre-footage recovery 40 pct greater than that of a similar field having only normal initial pressure. Comparatively little subsurface pressure testing has been done in the D-7 zone because of difficulties encountered in running instruments against high pressures in the presence of wax and bitumen, but fragmentary data suggest that the recovery for pressures above the bubble point, as calculated, is a reasonable expectancy.

WELL BEHAVIOR

The permeability to air of the D-7 sands is generally low, ranging up to several hundred millidarcys but averaging less than 50 millidarcys. Productivity indexes of wells penetrating the entire zone—about 1000 ft—are usually less than 0.5 bbl per day per pound per square inch.

Since nearly all wells have bottom-hole pressures in excess of the bubble point, gas-oil ratios are steady at the solution value of 900 ± cu ft per barrel. In the absence of free gas in the formation, the relative permeability to oil is sensibly constant; productivity indexes therefore have not declined with time. Indexes might be expected to (1) increase slightly because of a decrease in oil viscosity with pressure or (2) decrease due to a reduction in permeability as the sediments settle on loss of fluid pressure. However, no systematic variation has been observed, possibly because of inaccuracies inherent in the testing procedure.

Where static pressures have been observed on a particular well, the decline with respect to recovery is approximately linear. The curve may be slightly concave upward, owing to an expanding area of influence or declining production rates, or both. In more developed areas, the curve may become concave downward because of interference from more recent completions.

While the so-called mobility ratio, or ratio of permeability to viscosity, is below the average for California fields, the condition is offset by the high-pressure gradients that can be developed. Thus relatively wide spacing can be relied upon to deplete the reservoir almost to the bubble point. Thereafter closer spacing is probably desirable. However, by deferring drilling until the less expensive wells are actually needed, attractive economies result.

All wells, of course, produce by natural flow. Principal production problems involve the handling of asphaltene, paraffin, and sand produced with the oil. These settle out of the fluid, bridging the tubing string or plugging the surface bean. While the deposition of asphaltenes is not well understood, it has been attributed to the retention of gas in solution as temperatures decline in the course of the fluid's rise to the surface. To liberate gas in the tubing, to maintain the warmth of the rising column as much as possible, and to provide sufficient velocity to keep suspended matter moving, relatively high rates—of the order of 1000 bbl per day—are employed on new wells. On the other hand, too high a rate frequently results in excessive sand trouble and liner failure. Between these extremes delicate control is necessary if the wells are to produce steadily. The problem has been combated most suc-

cessfully by a method initiated by the Shell Oil Co., wherein well production is augmented by tank oil injected into the casinghead under pressure.[16] It is anticipated that as pressures decline, asphaltene deposition will become a factor of diminishing importance.

Hazards associated with surface pressures up to 5500 psi are greatly minimized by using equipment of adequate capacity and the testing of casing to 80 pct of its calculated yield. Coping with pipe trouble opposite the producing horizon remains largely an unsolved problem. The condition probably is aggravated by low permeabilities. The difference between static and producing pressures may exceed 4000 psi in some wells. The high pressure gradient at the well bore, combined with the compacting forces of the overburden, probably result in stresses exceeding the strength of even a well-consolidated sand, causing it to spall and slough. Because the modulus of elasticity of rock is much less than that of steel, the compaction of the sediments also induces very high vertical compressive stress in the pipe unless by chance it has freedom of movement. In addition, the shales may manifest the properties of a plastic, and, by heaving into the borehole, throw high collapsing pressure on the pipe. This, combined with the axial compression, promotes more rapid failure; in short, sand cutting, collapse, and shearing of the pipe becomes almost chronic. As of October 1946, pipe had gone bad in weight wells out of 33 completed in the zone.

Acknowledgments

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DISCUSSION

J. L. Arthur*—Mr. Watts has presented a paper, which points out that the initial

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formation pressure of the D-7 zone at Ventura is equivalent or nearly equivalent to the geostatic pressure. Most of the paper discusses other high-pressure oil fields in the world and the reasons that have been advanced for the excessive pressures in these fields, and the opinions of various authors who have investigated this problem and other related problems.

I have given very little thought to the reason for the excessive pressures in the D-7 zone or the zones above it, since the initial formation pressures of all Ventura oil zones were considerably in excess of the hydrostatic pressure, as my main concern is to make recommendations with a view to exploiting these high-pressure zones at the optimum profit. It is sufficient for me to know that these zones are of excessive pressure, that the Ventura field is a highly complicated structure, and that it is situated in an area subjected to tremendous pressures from major thrust faults, the overriding blocks of which moved both from the north and from the south toward this structure. It seemed sufficient for our purpose that the pressures built up by the movements on these thrusts could cause the excessive pressures found in the various oil reservoirs by folding and squeezing the reservoirs after all or most of the accumulation had taken place.

One of the theoretical problems not cleared up either by this hypothesis or by Mr. Watts' paper is the break in pressure gradient at the top of the D-7 zone. A curve for pressure versus depth, from the A-2 to the base of the D-6 zone, is practically a straight line, but at the top of the D-7 zone the pressure suddenly increases by about 2000 psi. I have no explanation for this, but would merely suggest the possibility that the deeper beds were subjected to more intense pressures than the zones above.

The difficulties encountered both in drilling and producing the D-7 zone wells have prevented the operators from obtaining any appreciable amount of engineering data; however, results obtained to date from a group of wells in the central portion of the field show that the recovery by fluid expansion will be of the order of magnitude indicated in Mr. Watts' paper. Estimates of the recovery efficiency to be obtained by depletion mechanics are difficult to make because the productivity indexes of some of the wells indicate that the average sand permeability in the zone may be extremely low.

T. L. Bailey*—Mr. Watts' paper is an interesting, thought-provoking and logically presented contribution and I agree with most of his reasoning and conclusions. My principal suggestion, which may affect the validity of some of his arguments, is that he bring his geological history of the Ventura region up to date. On account of the wide acceptance for so many years of the erroneous idea that the main southern California Coast Range faulting and folding was post-Pliocene and pre-Pleistocene, it is difficult for most engineers and geologists to realize the recency of our basin-ward Coast Range folds and their rapid growth and erosion.

Instead of starting growth at the beginning of the Pleistocene (as stated by Watts on page 196) the structural stratigraphic and paleontological evidence indicate clearly that there was no important folding at the site of the Ventura anticline until middle or late Pleistocene time. The lower Pleistocene (San Pedro formation) constitutes the Quaternary that Watts assigns a thickness of 3000 ft. He seems to have overlooked the significance that this San Pedro dips 45° to 90° and is quite conformable with the underlying lowest Pleistocene, Santa Barbara (also called Mud Pit shale or Upper Pico shale). The Santa Barbara in turn is conformable with the subjacent Pliocene, Pico formation, that grades downward into the lower Pliocene, Repetto faunal zone, in which the D-7 zone of the Ventura field occurs. Incidentally, the true base of the Pleistocene seems to be about the middle of the Santa Barbara formation, at the base of the cool-water *Pecten caurinus* faunal zone; this cool-water fauna apparently signified the advent of the glacial epoch. I summarized the evidence for the late Pleistocene age of the main Coast Range orogeny in southern California in a paper published by the Geological Society of America in 1943.[17]

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[17] T. L. Bailey: Late Pleistocene Coast Range Orogenesis in Southern California. *Bull.* Geol. Soc. Amer. (1943) 54, 1549–1568.

Most of the Santa Barbara formation is preserved by downfolding in the syncline north of the Ventura Avenue field, and there is no reason to suppose that all of the Santa Barbara and most of the San Pedro were not originally deposited over the Ventura anticline. The principal point I wish to bring out is that the Ventura anticline did not begin to fold until middle or late Pleistocene time, between the completion of San Pedro deposition and the deposition of the gently tilted nonmarine terrace deposits that rest with great angular unconformity upon the beveled edges of the San Pedro. The difference in dip amounts to 30° to 60° along the southern edge of the Ventura Hills, 2½ miles south of the oil field. This unconformity marks the interval during which the anticline was uplifted and 8000 or 9000 ft of Pilocene and Pleistocene were removed from its apex. A maximum of 10,250 ft of sedimentary rocks (4200 ft of Pico, 2900 ft of Santa Barbara and over 3100 ft of San Pedro) have been removed from the apex according to measurements made on the south flank, but I am allowing for 1000 to 2000 ft of combined late Pleistocene and recent stripping plus thinning of the San Pedro at the axis compared with the south limb. Assuming with Watts that the base of the Pliocene is 500 ft below the deepest stratigraphic penetration plus 9200 ft to the D-7 zone now being developed, we obtain a thickness of 9700 ft of subsurface beds above the base of the Pliocene at the apex. If we add the 8000 to 9000 ft that were present originally we obtain 18,000 or 19,000 ft to the base of the D-7 zone when the anticline began to rise, or 3000 to 4000 ft more than Watts calculated. Therefore it is quite possible that original depth of burial is responsible for the major part of the high pressures in the D-7 zone. Also, as the Ventura anticline is a similar fold, there is a pronounced thickening of strata in the axial part of the fold compared with the same beds on the limbs. In three carefully constructed sections made across the Ventura oil field some 13 years ago, using detailed surface and subsurface data and deducting 800 to 1000 ft of repetition due to the thrusting then known, I found that an axial thickening of 26, 32 and 44 pct respectively, between the lowest surface beds and subsurface beds 5000 to 5500 ft deep at the axis was required to make the surface and subsurface structure fit together. The 44 pct thickening was in a section about a mile west of the Ventura River, near the point where the Red Mountain thrust approaches closest to the anticlinal axis, and may have been accentuated by the crowding effect of that thrust on the north. It may be somewhat excessive, possibly including repetition by unrecognized faulting. This crestal thickening, which presumably is due to slow plastic flow of poorly consolidated clays and shales from the limbs toward the axis, evidently has been going on ever since the folding began. If only a 25 pct axial thickening is used it would give an additional 4500 ft of overburden. This crestal thickening and the piling up of still another 2000 ft in the crestal region by thrusting, probably in late Pleistocene and Recent time, would tend to compensate for removal of much of the original overburden by surface errosion and help to preserve the high pressures. So you see it is quite easy for me to get more than the 20,000 ft of original overburden required for the high pressure in the D-7 zone.

In my opinion, lateral (north-south) compressive forces are also partly responsible for the driving out of water, and why not some oil and gas as well, from the interbedded shales and into the sandstone reservoirs under excessive pressure? In my experience, both with the outcropping beds in the field and with cores as deep as 7500 ft, this squeezing out of fluids from the shales is accompanied to a minor extent by actual small injections of sheared shale into cracks and fractures in massive sandstones. One such shale tongue on the Gosnell lease starts as a bedding-plane slip, cuts through some massive sandstones by piling up in various contortions and finally offsets one sand bed at least 25 ft. The top of this shale tongue has actually pushed up the base of the overlying flat terrace gravel and intruded the gravel nearly a foot; also, the late Pleistocene terrace deposits in road cuts at the northeast edge of Ventura showed offsets along several minor faults of as much as 12 ft. These shale intrusions and minor reverse faults indicate that the folding and faulting strains are still operative.

E. V. WATTS (author's reply)—A portion of Mr. Bailey's criticism is due to the existence

of more than one geologic timetable. While Mr. Bailey considers the Santa Barbara to be Pleistocene, Grant, Eaton, Stewart, and others have classified it as Upper Pliocene. The latter viewpoint was accepted for the present purposes, so that the entire thickness of the Santa Barbara formation is already included in the 15,400 ft assigned to the Pliocene. Regarding the San Pedro formation, I am aware that up-to-date geologic opinion considers the profound disastrophism of the Pleistocene to have occurred in the middle and early upper portion of the epoch. However, Mr. Bailey's mention of "thinning of the San Pedro" suggests that he is in agreement with the thought that folding had actually commenced in what is here considered to be the beginning of the Pleistocene. Assuming that the Ventura anticline was covered with something less than 2000 ft of the San Pedro, the depth of burial of the D-7 zone can therefore be placed at 14,900 to 16,900 ft.

Or, if it is desired, we can make use of Mr. Bailey's estimate of 8000 or 9000 ft as the thickness of formation removed from the apex of the field. His estimated crestal thickening of 25 pct and repetition of 2000 due to thrusting appear reasonable, but it is important to note that these effects tend to reduce, rather than increase, the original depth of the beds. Using 9700 as the present depth to the base of the D-7 zone, *deducting* 2000 ft for repetition and *dividing* by 125 pct to correct for axial thickening, we have left 6200 ft for the original thickness of the present sediments. This, together with 8500 ± ft of degradation assigned by Mr. Bailey, totals 14,700 ft, which is very close to the original figure of 14,900 ft.

Regardless of how deep the Ventura sediments may have been at one time, the chief argument tending to invalidate the theory of "inherited pressures" is the matter of temperature change. If, as explained in the text, the beds cool more than 0.85°F per 100 ft in their elevation to present depths, the thermal contraction of the fluids is such that the present pressure will actually be subnormal. Or putting it another way, excessive pressure is more likely to be generated when a reservoir is sealed at a shallow depth and then submerged to a warmer level.

Mr. Arthur has had much practical experience as a development engineer in the Ventura Avenue field. His pragmatic approach to the general phenomenon is understandable and has a certain amount of logic if we are to exclude tensile systems—that is, reservoirs in which the faulting is normal. In a reservoir such as the D-7, it can be readily agreed that faulting seals the sediments, but we can only speculate on how strong a container the reservoir then becomes. As suggested by the appended calculations, sandstone may be so fragile that further application of lateral forces causes further faulting before a geostatic fluid pressure can be reached.

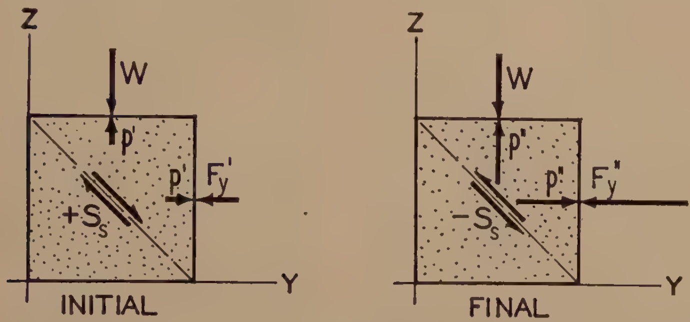

Fig 3—Unit cube of sandstone oriented so x-y plane is horizontal.

Calculations

To calculate the maximum pressure that can be generated in a formation by the application of horizontal forces, assume that a unit cube of sandstone is oriented so that the X-Y plane is horizontal (Fig 3). The cube is sealed on all surfaces against the migration of fluid contained in its pores.

Let S_s = shear strength of sandstone.
S_x, S_y, S_z = principal stresses applied parallel to the X, Y, Z axes, positive if compressive.
F_x, F_y = unit force applied to exterior of cube horizontally.
W = unit weight of overburden.
p = internal fluid pressure.

Primes denote values at initial time; double primes denote values at final time.

Then, according to the laws of combined stresses, the maximum shear stress occurs on each of two planes inclined at 45° to the two principal stresses whose algebraic difference is greatest and is equal to one half the algebraic difference. Therefore, the greatest increase in pressure p, due to an increase in horizontal forces F_x and F_y will be obtained if: (1) $F_x = F_y$ and (2) F_y' is so low that the cube is on the verge of failing by normal faulting and F_y'' is so high that the cube is on the verge of failing by thrust faulting (Fig 3).

$$\text{That is: } S_s = \frac{S_z' - S_y'}{2} = \frac{S_y'' - S_z''}{2} \qquad [1]$$

$$\text{where } S_z = W - p \qquad [2]$$

$$\text{and } S_x = S_y = F_y - p \qquad [3]$$

$$\therefore S_s = \frac{W - p' - (F_y' - p')}{2} = \frac{W - F_y'}{2} \qquad [4]$$

$$\text{also } S_s = \frac{F_y'' - p'' - (W - p'')}{2} = \frac{F_y'' - W}{2} \qquad [5]$$

$$\text{Adding, } 4S_s = F_y'' - F_y' \qquad [6]$$

$$\Delta S_x = \Delta S_y = S_y'' - S_y' = (F_y'' - F_y') - (p'' - p') \qquad [7]$$

$$= 4S_s - \Delta p \qquad [8]$$

$$\text{and } \Delta S_z = S_z'' - S_z' = (W - p'') - (W - p') = -\Delta p \qquad [9]$$

Letting E = modulus of elasticity of sandstone,
μ = Poisson's ratio,
and Δx, Δy, and Δz = unit elongation of the cube due to principal stresses, parallel to the respective axes,

$$\Delta x = -\frac{1}{E}[\Delta S_x - \mu(\Delta S_y + \Delta S_z)] \qquad [10]$$

$$\text{and } \Delta z = -\frac{1}{E}[\Delta S_z - \mu(\Delta S_x + \Delta S_y)] \qquad [11]$$

$$\text{From Eq 3} \quad \Delta S_x = \Delta S_y \qquad [12]$$

$$\therefore \Delta x = \Delta y = -\frac{1}{E}[\Delta S_y(1 - \mu) - \mu S_z] \qquad [13]$$

$$\Delta z = -\frac{1}{E}[\Delta S_z - 2\mu \cdot \Delta S_y] \qquad [14]$$

The change in volume, ΔV, due to the change in principal stresses, then, is

$$\Delta V = \Delta x + \Delta y + \Delta z = -\frac{1}{E}(1 - 2\mu)(2\Delta S_y + \Delta S_z) \qquad [15]$$

Assume that the entire change in bulk volume, ΔV, is due to a change in void volume. There will also be an additional change in void volume due to the reduction in size of individual sand grains, resulting from application of internal fluid pressure. However this change $\left(\text{equal to } \frac{\phi \cdot \Delta p}{B_q}, \text{ where } \phi = \text{porosity and } B_q = \text{bulk modulus of quartz}\right)$ is relatively small and can be ignored.

The change in fluid pressure, Δp, is related to ΔV as follows:

$$\Delta V = -\phi \cdot \beta_f \cdot \Delta p \qquad [16]$$

where ϕ = porosity
and β_f = compressibility of the liquid.
Combining Eqs 15 and 16 and substituting values for the stresses ΔS_y and ΔS_z from Eqs 8 and 9, we have that

$$\Delta p = \frac{8S_s}{3 + \phi \cdot \beta_f \dfrac{E}{1 - 2\mu}} \qquad [17]$$

Carpenter and Spencer report the compressibility of sandstones under uniform triaxial loading; this compressibility can be related to the modulus E by the following expression:

$$\beta_s = \frac{3(1 - 2\mu)}{E} \qquad [18]$$

Combining with Eq 17,

$$\Delta p = \frac{\frac{8}{3} S_s}{1 + \phi \dfrac{\beta_f}{\beta_s}} \qquad [19]$$

A plot of Carpenter and Spencer's values of compressibility β_s versus the porosity ϕ of their samples indicate that within the range investigated

$$\frac{\beta_s}{\phi} = -2.8 \times 10^{-6}, \text{ approximately.}$$

β_s is actually a function of the pressure, but unlike the compressibility of nonporous, brittle materials, decreases as the pressure increases. The value shown for β_s/ϕ will therefore be used as applicable up to the point of failure. From Table 2 the compressibility of liquid weighted according to pore saturation = -8.9×10^{-6}. The compressive strength of sandstone (unrestrained at right angle to the stress) seldom exceeds 6000 psi. Since the failure is essentially in shear

$$S_s = \frac{6000}{2} = 3000 \text{ psi.}$$

Introducing these values in Eq 19 gives

$$\Delta p = \frac{8/3 \times 3000}{1 + \frac{8.9}{2.8}} = 1900 \text{ psi.}$$

Thus the strength of sandstone apparently permits the generation of less than half the "excess" pressure necessary to obtain a geostatic gradient at 9000 ft. Most of the allowances have been toward higher calculated values of Δp. Furthermore, it would be difficult to stress an entire structure uniformly to the degree indicated in a unit cube.

Diamond Coring in the Rangely Field, Colorado

By Carl J. Christensen*

(Denver Meeting, October 1947)

Abstract

This paper presents the development of diamond coring of the Weber sand section in the Rangely Field, Colorado. The description and operation of the diamond-coring equipment is included as well as the economics and results obtained by its use. Diamond coring is compared with the other methods used for drilling the Weber sand. Two types of diamond coring are discussed. The first and the one used most extensively is the regular $6\frac{1}{8} \times 3\frac{3}{4}$-in. diamond bit and bottom hole 50-ft barrel. The second type, which has also been used successfully by Stanolind, consists of a $4\frac{13}{16} \times 2\frac{11}{32}$-in. cutting bit and reverse circulation coring equipment. The first type will be referred to as regular or conventional diamond coring while the latter type will be referred to as reverse circulation diamond coring.

Introduction

Diamond coring has been used for many years in mines, quarries, surface coring at dam sites, laboratory work, and so on, but, until recently, had never been used very extensively in coring oil sands and other oil-bearing strata. It was demonstrated early in its development that hard formations could be cut rapidly and that core recoveries far exceeded those obtained with conventional hard rock bits and quite often 100 pct recovery was obtained. However, the poorly constructed diamond-coring equipment and resulting high costs of early diamond coring slowed down its progress.

Early in the development of the Rangely Weber field, Rio Blanco County, Colorado, the Rangely Engineering Committee selected key wells that were to core the Weber section in its entirety. These cores were to be analyzed and various sections tested to gather sufficient information so that accurate reservoir studies could be made. The number of wells selected were kept at a minimum inasmuch as the productive Weber section, which is found at an approximate depth of 6000 ft, is thick, being as much as 600 to 700 ft on top of the structure. The Weber section is also comparatively hard to drill. For instance, one well took 60 days to core 490 ft of Weber sand with conventional coring equipment. It was noticed, however, that Core Laboratories' diamond plug cutter could quickly cut a plug from one of these hard cores. This fact led to the serious consideration of diamond coring the Weber sand.

The first diamond coring at Rangely was performed by Stanolind in August 1946 and, although we experienced some difficulties, the results definitely indicated that diamond coring would be successful at Rangely for coring the Weber sand. As more wells were cored and the equipment improved somewhat, diamond coring became less expensive than drilling the Weber sand with the conventional rock bit. In less than one year diamond coring has definitely proved its usefulness in oil-field drilling operations in the Rocky Mountain area where formations quite often drill very hard. The practice of spot coring in hard oil-bearing formations with conventional coring equipment is giving way to diaimond coring of the entire sections, thus givng an operator the complete picture.

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Regular Diamond Coring

Description of Equipment Used

The regular diamond-coring equipment is used almost exclusively at Rangely to core the Weber section. Reverse circulation coring has been successfully used on a Stanolind well and will be discussed briefly later on. The regular diamond-coring equipment cuts a 6⅛-in. hole and removes a 3¾-in. core, thus being referred to as a 6⅛-in. od × 3¾-in. id core head and core barrel. The lower section of the core barrel is shown in Fig 1 with the diamond core head in place, ready for coring. The core barrel consists of an outer and an inner barrel. This particular barrel is a 25-ft barrel but the standard barrel now being used will cut a 50-ft core. The outer barrel of the 50-ft core barrel is a two-section, plain barrel, 5⁹⁄₁₆-in. od with a set of stabilizing ribs welded approximately 18 in. above the bit. Another set of stabilizing ribs are welded on a sub which is screwed into the top of the barrel. Construction of these stabilizing ribs can be seen in Fig 2 on the outer barrel. In this case they were welded onto the barrel instead of a sub that fits on top of the barrel. These stabilizing sections are 6¹⁄₁₆ in. in diameter and serve two purposes: (1) they keep the barrel from wobbling in the hole and force it to cut a straight core and, (2) they take all of the wear away from the outer barrel. The stabilizing sub was developed to eliminate welding on the barrel. The sub can be exchanged without shopping the core barrel for building up the ribs.

Fig 1—Lower section of core barrel with diamond core head in place.

Fig 2—Construction of stabilizing ribs on outer barrel.

From top to bottom in Fig 2 can be seen the top or head of the core barrel, the bearing on which the inner barrel is free to turn

independent of the outer barrel and head, the top of the inner barrel, and the top of the outer barrel. In the photograph the head is unscrewed from the outer barrel and the inner barrel is pulled up out of the outer barrel. The circulating fluid passes down through drilled holes in the head and through the annulus between the inner and outer barrels. A small port with a ball and seat is provided in the top of the inner barrel which keeps the circulating fluid from passing down inside the inner barrel but allows fluid to escape out of the top of the inner barrel as it fills with core.

Fig 3 shows two diamond core heads and a spring core catcher. The diamond core head on the left has fewer water courses than the other. The one on the right has 24 courses and was found to be most satisfactory in cooling the head and removing the cuttings.

The diamond core head is made up principally of two parts, the matrix in which the diamonds are set, and the blank upon which the matrix is fastened. The matrix is made of a hard special alloy while the blank is an ordinary tough alloy steel. Diamond setting is a highly skilled and highly developed process which has been developed over many years and it is this fact that makes it possible for such a delicate bit to stand the abuse of oil-well coring. A mold is machined from hard carbon to the exact form of the matrix. In this mold each diamond is set individually and correctly for cutting. The matrix alloy, which is in a powdered form, is poured into the mold. It is then placed in a furnace and sintered at proper temperature to form the finished matrix. The diamonds are set in a definite pattern on the matrix to produce most efficient cutting. The matrix is then fastened to the blank to form the finished head. One manufacturer of diamond bits screws the matrix to the blank and then keys it in place. Another manufacturer molds the matrix to the blank in the diamond-setting process. The diamonds most commonly used are "Bortz" diamonds, which are hard commercial diamonds. A $6\frac{1}{8} \times 3\frac{3}{4}$-in. head will contain approximately 200 carats. There are a number of other grades and sizes of diamonds used for oil-well diamond coring heads. One operator has obtained excellent results with large "Congo" grade diamonds, which are a softer grade of diamond than the "Bortz" and somewhat less expensive.

FIG 3—TWO DIAMOND CORE HEADS AND A SPRING CORE CATCHER.

The core catcher shown between the two diamond heads is used to break off and hold the core. The design is simple but very effective. It is split in one place and slightly smaller in the unsprung position than the core to be cut. It is made of a spring steel and the inside edge is covered with a hard metal coating to prevent it from wearing out quickly. The catcher is tapered and fits into the core head. While cutting the

core the catcher rides up against the inner barrel and does not rotate with the outer barrel but remains stationary with the core and inner barrel. The outer barrel rotates with the drill pipe while coring. The core that is cut feeds through the core catcher up into the inner barrel. Circulating fluid passes down the drill pipe, through holes bored in the head, down the annulus between the inner and outer barrels, through the holes shown in the core catcher, through the water courses in the bit and then out the drill pipe and casing annulus. After the core is cut it is broken off by pulling up on the drill pipe. During this operation the outside taper on the core catcher causes it to squeeze down on the core harder and harder as more tension is placed in the drill pipe.

Fig 4 shows the procedure used in removing the core from the barrel. A piece of core about 4-ft long protrudes from the core barrel and is broken off by use of a hammer or sledge. Long sections of continuous core are not uncommon. You will note from the picture that the downward motion of the core can be controlled by applying a friction grip on it with the special tool shown.

Operation of Diamond-coring Equipment

In operating any type of mechanical equipment care must be taken if failures are to be prevented. In the case of operating diamond-coring equipment this is extremely important. The success and savings resulting from the use of diamond-coring equipment depend to a great extent on using proper technique. It is impossible to set any hard and fast rules for the operation of the equipment under all conditions and in all types of formations. There are, however, a number of general rules that will help to keep failures at a minimum. Most of these rules have been developed through analyzing failures at Rangely and elsewhere. They can be stated briefly as follows:

1. All metal junk must be removed from the well bore before commencing diamond coring.

2. The core barrel should be checked thoroughly after cutting every core. The circulating ports in the head will plug with coarse material from the mud. Bearings on which the inner barrel rotates must be checked for wear.

FIG 4—REMOVING THE CORE FROM THE BARREL.

3. Drill collars used above the core barrel should be straight to eliminate unnecessary wear on the stabilizing ribs and to prevent undue stress in tool joints.

4. Before commencing diamond coring in a larger hole than the diamond head, it is advisable to drill a rat hole about ⅛ in. larger than the diamond core head for a few feet.

5. Some float equipment used in cementing casing strings contains metal springs and other metal parts and should not be used. Extreme precaution should be taken to keep junk from entering the hole.

6. If the completion program can so be arranged, provision should be made for a casing string to the top of the sand that is to be diamond cored. Unsatisfactory results caused by damaged diamond heads were experienced in two wells in the Rocky Mountains where large sections of open hole containing shale formations provided shoulders where junk had accumulated and later fell into the hole while diamond coring. The holes had been cleaned prior to coring.

7. Rock bits used for drilling the hole prior to coring should be ⅛ in. larger than the diamond head to be used for coring. A 6¼-in. hard rock bit should be used ahead of the 6⅛-in. diamond bit.

8. Rotary table speed and fluid volume through the system should be set for coring when about 6 to 12 in. above the bottom of the hole. The bit should then be lowered gradually until it has cut a uniform seat over all of its face. In certain types of hard fractured formations a small piece of loose core might remain in the hole. If the bit is lowered rapidly with full weight on the bit from the start, the hard piece of loose core will roll around and damage the matrix on the inner periphery. The diamond head is actually damaged more under these conditions than in cutting an entire 50-ft core.

9. When a core catcher fails and leaves several feet of core in the hole the core barrel should not be rotated while going down over the core unless a different head is being run. The weight indicator should be watched closely, however, and if there are any signs of the bit taking weight, the bit will have to be rotated. In most cases the core remaining in the hole is not broken off and it is possible to go down over it.

10. After cutting a core it is broken off by shutting down the rotary table and pulling up on the drill pipe. By watching the weight indicator it is possible to tell when the core breaks off. Usually a straight pull of 10,000 lb will break a core off, this, of course, depending on the formation's physical characteristics. If a straight pull fails to break the core, the drill pipe can be rotated slightly to break off the core by twisting. Tension must be maintained during the twisting operation.

11. Use a sufficient number of drill collars so that all the weight to be used on the bit will be in the drill collars, thus leaving the drill pipe in tension.

12. It is very noticeable when a diamond bit ceases to cut inasmuch as diamond coring time is low, sometimes as low as 3 min per foot. Also, a diamond bit will cut as fast just before failing as it did when first run in the hole. Therefore, when cutting ceases, either the diamond bit has failed or the core barrel is plugging, and it is advisable to come out of the hole and check the equipment. If this is done, larger salvage values are obtained on the bits.

13. While diamond coring, uniform and constant weight should be maintained on the bit at all times. Allowing the bit to drill off not only doubles the drill time but is harder on the bit.

14. Even though the diamond-setting process has been highly developed, there is usually a small variation in the size of diamond heads. A variation in outside diameter of a few thousands of an inch will make it necessary to ream down a larger head being run behind a smaller head. If the section to be cored will require two or three heads, the largest head should be used first, and so on. A ring gauge can be used to check the outside diameter of the bits so that reaming can be eliminated.

15. After running a junk sub to ensure a clean hole, stripper rubbers should be used on all trips going in and coming out of the hole. Tong dies and other metal parts are always getting in the hole and the above precaution should be taken.

The amount of weight to carry on the bit, rotary table speed and amount of fluid to be circulated through the system while coring, are variable, depending on the formation being cut and the size of bit being used.

This must be established in each field for each size head and for the kind of fluid or mud being used. General practice is to start out with the lowest weight, table quickly wears around the face of the bit and shuts off circulation, which, in turn, increases the pump pressure. By watching the pump pressure it is possible to detect a

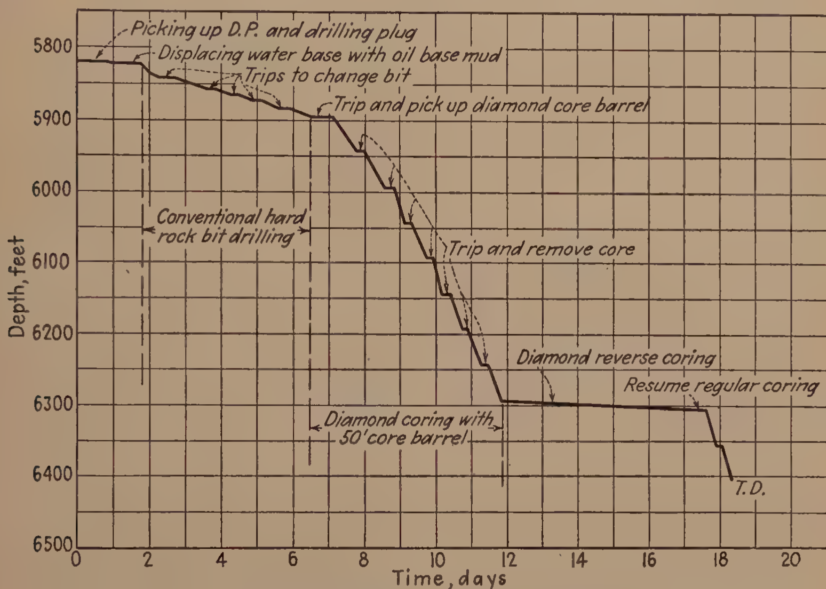

FIG 5—DRILLING VS. DIAMOND CORING.
Depth-time log of Stanolind's Well No. 5, Weber sand section, Rangely, Colo.

speed, and the like, as found for similar conditions elsewhere and increase these factors until the most desirable operating conditions are determined. Approximately 100 gpm of oil-base mud should be circulated or 80 gpm of water-base mud. Water-base mud has much greater erosive action on the bit than oil-base or emulsion mud. The pressure and volume of water-base mud should be kept just high enough to carry away the cuttings and cool the head. On the other hand, oil-base mud has a tendency to plug the water courses if a sufficient volume is not circulated. Therefore, it is usually necessary to circulate a larger volume of oil-base mud than water-base mud. Once the proper volume of fluid has been checked the particular pump pressure while circulating this volume can be used by the driller to detect any change of conditions. When a bit fails, a groove bit failure, providing nothing else is restricting the flow of fluid through the system.

For the Rangely Weber sand section we have found a rotary table speed of 125 to 150 rpm and a weight of 3000 to 5000 lb on the bit to be most satisfactory. Coring time under these conditions varies from 3 to 4 min per foot in porous sand to 30 min per foot in shale, average time being 9 to 10 min per foot.

Discussion

During August 1946, diamond coring was initiated by Stanolind at Rangely. A 25-ft core barrel with a 6⅛-in. od by 3¾-in. id cutting head was used. The first diamond bit cut 70 ft before failing. The failure resulted from the loss of a couple of the sections or lugs from the bit. The second bit failed immediately when the matrix in which the diamonds were set broke away

from the steel body of the bit. While waiting for additional diamond bits we continued coring with a conventional core barrel and bits. A total of six diamond bits were used in this well to core 353 ft of sand giving an average life per bit of 58.8 ft. We received 100 pct recovery for the 353 ft cored and the average cutting time per foot was 9.6 min. In the same well we cored 119 ft with conventional rock bit coring, recovering 97 ft for a recovery of 80.8 pct. The average coring time for the 119 ft was 42.9 min per foot. Diamond coring proved to be far superior and much more economical than conventional coring on this well even with all the difficulties and bit failures experienced. The causes for the bit failures in this well have been corrected. The 6⅛-in. diamond matrices on the bits used in this well were molded in half sections and keyed to the steel blank. The bits now being used have matrices that are molded in one piece, making a more uniform and much stronger diamond bit. Failures resulting from the matrix pulling loose in the hole are now few.

After making a study of the coring in this first well, it was decided to try a 50-ft core barrel, thus cutting the number of trips in half. Longer wear could also be expected from the diamond bits because most of the wear and tear on the bits was received while making trips and commencing the next core. The results obtained with a 50-ft core barrel on overall cutting time is depicted on Fig 5. Approximately the first 75 ft of Weber section in this well was drilled with conventional hard rock bits and took seven bits and a total of 4.7 days. The next 398 ft were diamond cored which took a total of 5.6 days with one bit. The next few feet were cut with reverse circulation coring without success. The well was then completed after cutting two more 50-ft cores. Fig 5 can be taken as typical of diamond coring at Rangely with the 50-ft core barrel.

The first four wells cored with the 50-ft core barrel gave excellent results and the equipment worked perfectly. However, on the following three wells we experienced considerable trouble in operating the equipment. This time the difficulty was not the bits but the core barrel. Up to this time we were using only one stabilizing point on the barrel, which was at the top. The core that was being cut by the barrel was grooved, the groove forming a spiral around the core. After cutting several feet of this crooked core, the barrel became plugged solid and the equipment ceased to operate. This plugging condition of the barrel threw all of the weight being carried on the bit onto the inner core-barrel bearing. Failure of the bearing was frequent and quite disastrous. Broken parts of the bearing were pumped down between the inner and outer barrels, and in a few instances the core barrel had to be shopped to remove the inner barrel. We overcame this difficulty by welding stabilizing ribs on the 50-ft core barrel approximately 18 in. above the bit. This gave the outer barrel stabilization at the top and at the bottom and the difficulty was eliminated. These stabilization ribs are approximately $\frac{1}{16}$ in. less in diameter than the bit. Before correcting the trouble, we noticed that these crooked cores were always obtained while cutting the hard, dense dolomite in the Weber section.

The bearing on which the inner barrel floats while in operation is a critical point in the barrel. Although the bearing gives comparatively long service in oil-base mud, it should be checked on every trip and replaced periodically to eliminate failure while coring. A recess is now being cut in the inner barrel cap which will serve to catch and retain broken bearing parts. Another barrel is now being manufactured in the Rocky Mountain area which uses a completely sealed bearing. Although the writer has not had any experience with this barrel, this feature appears to have considerable merit.

The Rangely Weber sand is made up of hard, dense, dry dolomite and dolomitic

sand, gray hard shale, red shale, fine and medium grain sand, and sandy shale, containing some limey blotches, quartzitic sand and pyrites. Fig 6 shows the rate at which these various strata are cored with diamond bits. Generally the porous true sands core at a rate of five or less minutes per foot; sandy-dolomite with some porosity, at a rate of 5 to 10 min per foot; sandy shales with some porosity, at a rate of 10 to 15 min per foot; hard, dense dolomite, at a rate of approximately 15 min per foot; and true hard shales at a rate of 20 to 30 min per foot.

At the present time three major operators in the Rangely field are diamond coring the Weber sand section in practically every well and having the cores analyzed. This program has been developed as a result of the economics of diamond coring the Rangely Weber section. The section can be cored with diamonds at less cost than it can be drilled with conventional hard rock bits. Fig 7 presents a comparison of four methods that have been used to drill the Weber sand section. Reverse circulation drilling with hard rock bits has been used and proven very economical and satisfactory in the north and west portions of the field where the section drills much faster. However, crude oil must be used with reverse circulation to prevent loss of fluid to the formation. If oil-base or water-base mud is used, the circulating pressure in reverse circulation against the formation causes loss of fluid. Whenever crude oil is used around a conventional drilling rig, the danger of explosion and fire is always present. Therefore, this method has not been used extensively.

With the present program of diamond coring at Rangely, the writer feels that more coring data will be obtained in this reservoir than has ever been obtained elsewhere. Correlation of the Weber sand section at Rangely is practically impossible because of the varied sand conditions from one well to another. However, with the large amount of core data being obtained,

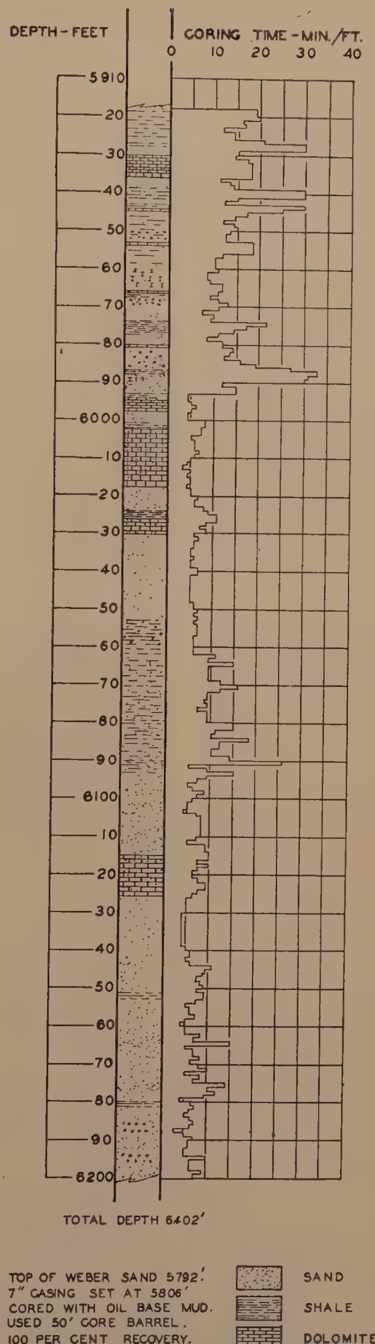

FIG 6—COMPOSITE LOG SHOWING CORING TIME AND FORMATION CORED.
Weber sand, Stanolind Well No. 5, Rangely, Colo.

reservoir studies will be more accurate and valuable. The data will also be very valuable for future shooting of the section,

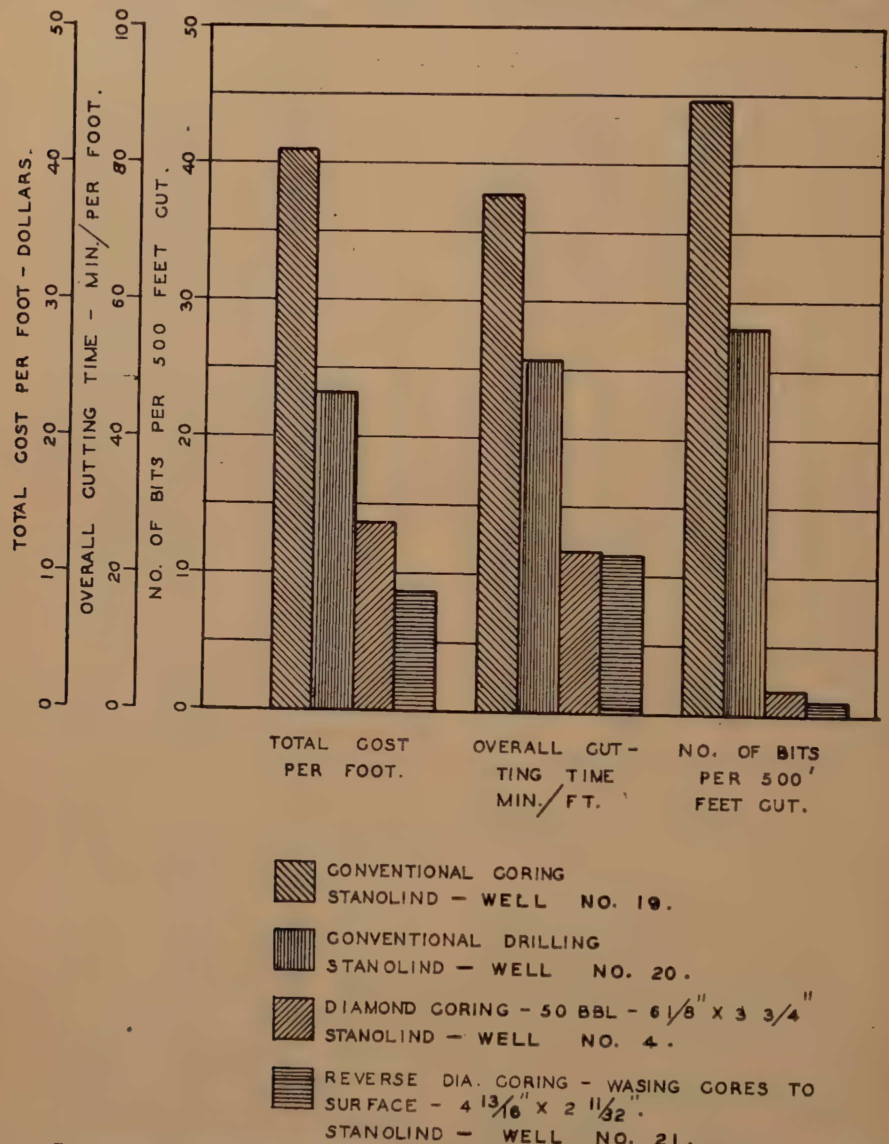

Fig 7—Comparison of methods used for drilling, Rangely Weber sand, Rangely, Colo.

water shut-off jobs, selective production to control gas-oil ratios, and so on. Data on diamond coring of the Rangely Weber sand is given in Table 1.

Trained drilling crews are essential if maximum benefit from diamond coring is to be obtained. Diamond coring requires constant attention from the driller. Most crews at Rangely are now familiar with diamond coring. The total footage drilled by a single bit is steadily increasing. Maxi-

TABLE 1—*Diamond-coring Data in the Rangely Weber Sand*

Well Number	Total Footage Cored	Number Diamond Bits	Average Ft Cored per Day	Cost of Bits	Rotary Rig Cost[a]	Total Cost	Total Cost per Ft	Remarks
1	353	5.0	29.4	$ 3,723.00	$ 7,257.00	$ 10,980.00	$31.10	25-ft core barrel
2	542	4.0	49.3	4,052.00	6,761.00	10,813.00	19.95	25-ft core barrel
3	64	0.1	51.1	142.00	770.00	912.00	14.25	50-ft core barrel
4	591	2.24	61.2	1,965.00	5,996.00	7,961.00	13.47	50-ft core barrel
5	494	0.8	83.8	1,149.00	3,050.00	4,199.00	8.50	50-ft core barrel
3	388	2.24	40.8	2,528.00	5,799.00	8,327.00	21.46	25-ft core barrel
4	548	2.00	37.0	1,685.00	8,924.00	10,609.00	19.36	25-ft core barrel
5	517	2.0	62.6	2,154.00	5,126.00	7,280.00	14.08	50-ft core barrel
6	248	0.9	43.7	969.00	3,523.00	4,492.00	18.11	50-ft core barrel
7	160	0.52	30.8	571.00	3,113.00	3,684.00	23.02	50-ft core barrel
8	517	3.0	37.6	3,230.00	8,371.00	11,601.00	22.44	50-ft core barrel
9	434	1.0	40.2	1,177.00	6,530.00	7,707.00	17.76	50-ft core barrel
10	332	1.3	62.3	1,400.00	3,311.00	4,711.00	14.19	50-ft core barrel
11	440	2.6	50.0	2,800.00	5,471.00	8,271.00	18.80	50-ft core barrel
12	450	1.1	63.4	1,180.00	4,414.00	5,594.00	12.43	50-ft core barrel
13	523	2.3	66.2	2,477.00	4,922.00	7,399.00	14.15	50-ft core barrel
14	279	2.6	48.1	2,800.00	3,581.00	6,381.00	22.87	50-ft core barrel
15	610	1.92	46.9	3,097.00	7,975.00	11,072.00	18.15	50-ft core barrel
16	348	0.9	48.1	969.00	4,481.00	5,450.00	15.66	50-ft core barrel
17	418	3.12	44.9	4,171.00	4,534.00	8,705.00	20.83	50-ft core barrel
18	130	0.36	29.4	485.00	2,673.00	3,158.00	24.14	25-ft core barrel
Total..	8,386	40.00		$42,724.00	$106,582.00	$149,306.00	$17.80	

[a] Includes cost of core barrel equipment.

TABLE 2—*Diamond Bit Record*
(Complete Data)

Bit	Number of Carats	Total Footage Cut	Total Cost	Net Cost	Net Bit Cost per Ft	Remarks
A	179.99	68.0	$ 1,169.70	$ 516.67	$ 7.60	Normal bit failure.
B	156.40	71.5	1,050.04	685.83	9.59	Normal bit failure.
C	139.68	94.5	954.98	910.03	9.63	Normal bit failure.
D	169.29	125.0	1,631.57	1,151.57	9.21	Normal bit failure.
E	197.39	223.5	1,828.22	915.77	4.10	Normal bit failure.
F	198.80	599.4	1,823.95	1,237.49	2.06	Normal bit failure.
G	194.60	2.0	1,794.44	899.84	449.92	Bit failure because of junk in hole.
H	194.87	125.0	1,791.92	1,039.70	8.32	Normal bit failure.
I	194.35	50.0	1,787.86	891.37	17.83	Piece of hard core damaged matrix.
J	183.11	93.7	1,791.24	909.38	9.71	Piece of hard core damaged matrix.
K	200.82	239.0	1,837.02	837.28	3.50	Some wear still remained in bit when salvaged.
L	183.11	258.0	1,709.64	847.31	3.28	Some wear still remained in bit when salvaged.
M	190.03	44.0	1,777.21	827.80	18.81	Lost key out of bit—returned for full credit.
N	197.14	49.0	1,828.30	1,277.45	26.07	Junk from float equipment in hole—ruined head.
O	200.48	279.5	1,746.42	1,116.35	3.99	Bit wore out on inner periphery because of setting down on hard pieces of core.
P	186.55	431.5	1,734.44	1,046.90	2.43	Head became loose. Returned to factory and then continued to use.
Q		400.0	2,599.76	1,145.26	2.86	Bit wore out on inner periphery because of setting down on hard pieces of core.
R	202.06	399.0	2,767.47	1,793.22	4.49	Matrix became loosened but reran after tightening.
S		202.0	2,935.68	1,479.00	7.32	Normal bit failure.
T		612.0	1,719.95	1,419.95	2.32	Bit failed. Matrix unscrewed—left in hole.
U		49.0	1,612.89	1,336.53	27.28	Bearings failed in barrel and dropped in hole ruining bit.
V	201.70	197.5	1,855.57	1,404.90	7.11	Had large diamonds set around inside diameter. Failed on face of bit.
Total.... Average..	22 bits	4,613.1 209.7	$39,748.27 $ 1,806.74	$23,689.60 $ 1,076.80	$ 5.14	

mum footage drilled with one bit has now reached 721 ft, and 400 to 500 ft per bit is not uncommon. However, the failures of a few bits because of unsuspected junk, hard pieces of core, and the like, lower the average footage drilled per bit. From Table 2 and 3 it can be noted that the average footage cut is over 200 ft per bit. A few failures are still to be expected but if they are kept at a minimum, satisfactory results are possible.

TABLE 3—*Diamond Bit Record*
(Cost Data Not Available)

Bit	Number of Carats	Total Footage Cut	Remarks
AA	158.55	120.0	Bearings failed in barrel damaging bit.
BB	177.04	50.0	Junk in hole ruined head.
CC	164.29	107.0	Junk in hole ruined head.
DD		345.8	Normal bit failure.
CC		200.0	Normal bit failure.
DD		439.0	Still some wear in bit.
EE		521.0	Still some wear in bit.
FF		215.0	Normal bit failure.
GG		488.0	Normal bit failure.
HH		41.4	Bit failed because of junk in hole.
II		291.0	Normal bit failure.
JJ		184.0	Normal bit failure.
KK		46.0	Still in good condition.
LL		176.0	Matrix twisted off in hole.
MM		107.0	Inner periphery failed.
NN		299.0	Normal bit failure.
OO		100.0	Matrix cracked and diamonds chipped out.
PP		42.0	Still in good condition.
Total....	18 bits	3,772.2	
Average..		209.6	

Several operators in the Rocky Mountain area outside of the Rangely field are now using diamond coring successfully. The Tensleep sand in Wyoming has been diamond cored successfully. A formation that is well cemented should diamond core with success. However, highly fractured, hard formations crumble and plug the core barrel. West Texas has experienced difficulty in coring hard cherty formations for this reason.

REVERSE CIRCULATION DIAMOND CORING

Diamond coring was a big success in the Rangely Weber sand right from the start. However, trip time was high and if it could be eliminated or reduced, a large saving would result. Diamond bits would cut 200 to 600 ft and therefore, it was not necessary to come out of the hole to change bits. Increasing the length of the core barrel to 50 ft reduced trip time by 50 pct. The use of reverse circulation diamond coring by which cores are washed to the surface as they are cut, eliminates all trip-time delays. This method of diamond coring was attempted several times but only on the most recent attempt did we obtain successful results.

On our first attempt, the equipment consisted of the following, starting from the bottom of the string to the surface:

1. A 4$^{13}\!/\!_{16}$-in. od × 2$^{11}\!/\!_{32}$-in. id diamond head.

2. A special core barrel approximately 12 ft in length, designed with an outer and inner barrel and resembling the standard 50-ft core barrel. The inner barrel, of course, had a flush opening to allow cores to pass on through and into the tubing string. It was designed so that the circulating fluid would not pass through the inner barrel, but up between the inner and outer barrel to a port in the top of the inner barrel.

3. Five 4¼-in. od drill collars having the same inside diameter as 2½-in. EUE tubing.

4. Adapter sub from drill collars to 2½-in. EUE tubing.

5. 2½-in. EUE tubing used as drill pipe.

6. A joint of 3-in. EUE tubing immediately under the Kelly which was called the receiving core barrel. In the bottom of this barrel was installed a flapper-type core catcher. A pin was placed near the top of the barrel to prevent cores from being washed out of the core receiver.

7. Regular Kelly.

This equipment proved to be unsatisfactory for two reasons. The bottom core barrel became plugged after filling up with core because no circulation was maintained in the inner barrel. Cuttings and broken

core could not be forced out of it. The tubing with recessed collars caused small pieces of core to hang up in the tubing string.

core was washed to the surface and recovered. At first, it was not known how often the core should be broken off, but after experimenting it was found that the

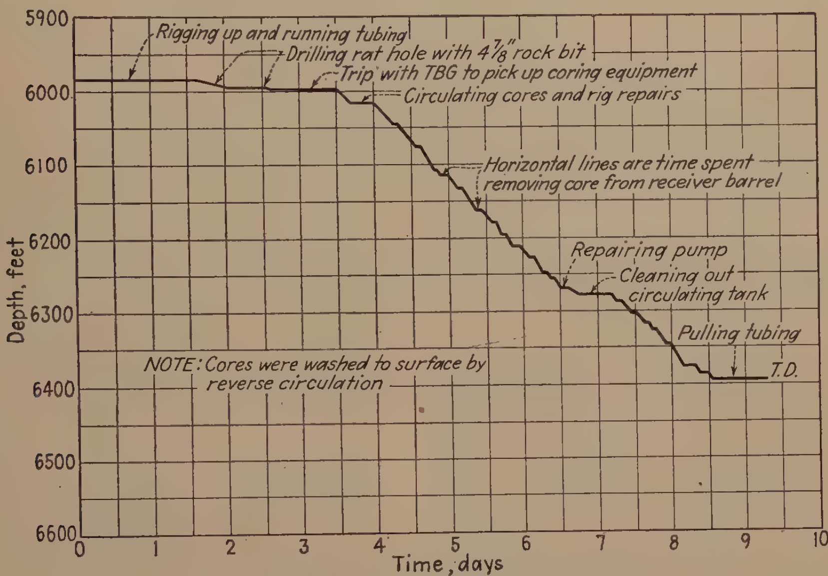

FIG 8—REVERSE CIRCULATION DIAMOND CORING.
Cutting-time log of Stanolind Well No. 21, Weber sand section, Rangely, Colo.

After changing the equipment somewhat, well No. 21 was successfully cored. The equipment was changed as follows: the bottom core barrel was removed and the diamond bit was reduced in inside diameter to 2$^{11}/_{32}$-in. to allow greater core clearance in the tubing. In place of the bottom-hole barrel, a special core breaker and catcher sub was designed which fitted immediately above the bit. Steel balls in tapered grooves clamped on the core upon pulling up on the tubing string. The tubing was made internal flush by placing ferrules in the tubing couplings. With these changes the equipment worked satisfactorily.

On Fig 8 are shown the results of reverse circulation diamond-coring equipment at well No. 21. A 4⅞-in. rock bit was used to drill a rat hole before the reverse diamond coring was started. A total of 399 ft of Weber sand was then cored without making a trip with the tubing. A total of 392 ft of

core should be broken off every 3 ft cut. The longest piece of core recovered was approximately 6 ft in length. This was recovered while the core was broken off at less frequent intervals.

Crude oil was used on this job as the circulating medium. Oil-base mud had been tried on another well but it was lost to the Weber sand whenever a piece of core hung up in the tubing and the pump pressure exceeded 300 psi. By using crude oil, greater pump pressures could be used to start stuck pieces of core without losing fluid to the formation. The surface equipment was connected up so that circulation could be reversed easily. This method was used to release stuck pieces of core in the tubing.

After cutting approximately half of the Weber section, the crude oil became loaded with fine sand cuttings. Only a small circulating pit was used and the small sand

cuttings did not have time to settle out. On subsequent jobs using this equipment, larger pits are to be used. A desander would be helpful in keeping the sand out of the crude oil.

Reverse circulation diamond coring of a second well will soon be commenced. The economics of this method over the others used at Rangely are shown on Fig 7. The results indicate reverse circulation diamond coring has considerable merit. There is the disadvantage of the reduced hole but this is not considered too serious. The productivity of well No. 21 has not been noticeably affected by its smaller bore hole.

Conclusions

1. Regular diamond coring with a 50-ft core barrel and a $6\frac{1}{8} \times 3\frac{3}{4}$ in. diamond bit in the Rangely Weber section has proved more economical than conventional hard rock bit drilling or coring.

2. The drilling rate with regular diamond-coring equipment has proved twice as fast as with conventional hard rock drilling at Rangely.

3. Diamond coring equipment has now been developed to a point where it is very sturdy and can be expected to give excellent service if operated properly.

4. Diamond coring will give approximately 100 pct recovery.

5. To obtain best results with diamond coring, personnel operating the equipment should be experienced.

6. Providing the diamond bits are all the same outside diameter the hole is always cut to gauge and no reaming down is necessary.

7. Water-base mud causes much more cutting action on the diamond bit than oil-base mud and also causes the bearings to wear out much more rapidly.

8. Reverse circulation diamond coring at Stanolind's well No. 21 proved to be less expensive than the regular diamond coring in the Rangely field.

9. Diamond coring in oil wells in the Rocky Mountain area is now commonplace.

Acknowledgments

This paper was made possible only because of data taken from Stanolind Oil and Gas Company's operations at Rangely. I wish to express my appreciation to Stanolind Oil and Gas Company for the permission to prepare and present this paper.

The assistance of Mr. C. Deely, with Drilling and Service, Ltd., is herewith acknowledged.

Acknowledgment is made to the engineers and production men at Rangely who have advanced valuable ideas toward making diamond coring a success at Rangely.

Radioactive Markers in Oil-field Practice

By H. G. Doll,* Member AIME and H. F. Schwede*

(New York Meeting, March 1947)

Abstract

This paper describes a method to provide identification of particular depths in a borehole through the use of radioactive markers. The correlation of a marker, placed in the wall of a borehole, with known points of the electrical log and with the casing collars in the cased hole permits accurate positioning of tools with respect to a formation, regardless of absolute depth. Such a process is particularly useful in gun perforation of a casing in a well. Technique and equipment are discussed and illustrated. Examples are given of practical application in the field.

Introduction

During the past decade the search for petroleum has increased the importance of testing zones at depths in wells which have become progressively deeper. The development of new techniques, such as electrical logging, has permitted the identification of producing formations which consist of comparatively thin strata. When thin beds are to be produced at great depths, the problem of positioning tools accurately to place the well in production becomes acute.[1]

Continuous consideration is being given in the petroleum industry towards the improvement of depth measurements in a borehole. The accuracy in absolute depth measurements, whether made in an open or cased hole, whether determined by a cable or a drill pipe, depends upon a number of factors, such as tension, temperature, and calibration.

For example, the effects of tension from the weight of 10,000 ft of drill pipe and the thermal expansion of this length of pipe, where its average temperature has increased 50°F, will produce an elongation as much as 8 ft.[2] The effects of such factors can be minimized through the use of care in depth measurements, the application of corrections based on experience, and continuous calibration or checking.

The fact that different methods and different tools are used to determine the depths of formations in wells will sometimes give rise to a difference between measurements. It is evident that an important requirement in a well is the ability to locate at will any subsurface point. While absolute depth measurements have improved in recent years, it is reassuring to have other means to verify, for example, that a casing is perforated at a particular place with reference to a zone within a formation. Such a check on measurements may be had by placing a reference marker at a point known with respect to the electrical log of the borehole. That point is usually chosen to be in proximity to the zone to be perforated. Thus, only short relative depth measurements are made and any inaccuracy becomes very small and of minor importance.

The use of reference markers located at fixed points predetermined in each zone where future operations are contemplated enables the operator to position any tool

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[1] References are at the end of the paper.

with great confidence. The positioning of the tool now requires the measurement of only a short interval, less than 100 ft, a measurement that can be accomplished easily. The elongation of cable or of pipe, caused by tension, temperature and other effects, which are difficult to estimate when dealing with long lengths, can be neglected.

The preference for short relative measurements is evident when it is recalled that an accuracy of 0.50 pct in depth discrimination will amount to only 6 in. when applied to an interval of 100 ft, but it will amount to 50 ft when applied to an absolute depth measurement at the bottom of a hole 10,000 ft deep.

The reference marker should be a simple device, easily placed at the proper position in the borehole and able to be identified for a long time after casing has been cemented. It should be of small size in order to permit very accurate location at a definite position. Several types of markers have been considered; namely, radioactive, magnetic and temperature markers.

For practical reasons the preference has been toward the use of a radioactive marker. Such a marker may consist of a compact source of gamma rays originating from a radium salt. The rays are able to pass through several inches of cement and steel, and they can be easily detected by suitable equipment. The source will outlast the life of the well inasmuch as half of the amount of radium salt used will still be active after 1590 years.

The location of the artificial marker after casing has been set will identify the depth of a point whose position is known with reference to the formations. Then, regardless of absolute depth, a tool or device may later be set in the casing at a given distance from the known point. To that point may also be tied in the casing collars which thereby provide another permanent set of references. It has already been mentioned that relative differences in depth over a short distance can be determined with greater satisfaction than absolute depths from a datum plane far removed.

The method outlined above consists essentially of three steps; namely, the placement of the marker with respect to known points on the electrical log, its location behind the casing, and its subsequent use as a reference point, such as for the location of the casing collars and the positioning of tools in the hole.

Apparatus

The apparatus comprises several main parts; namely, the radioactive marker, the instrument to place the marker in the open hole, the instrument to detect the marker after the casing has been cemented, including the detector sonde, its control panel, and a recorder.

The radioactive marker is a small brass capsule containing $\frac{1}{10}$ of a milligram of radium. The intensity of the gamma rays from such a point source, even as far as 2 ft, away is ample to register easily, through the casing and the cement, on the detecting apparatus employed. The radiation from the source overrides the background due to the natural gamma radiation in the hole and gives a distinctive reading regardless of the position of the marker when lodged in the wall of the hole.

The brass pellet is placed inside a steel projectile which is fired either by a sample-taker gun or a perforating gun. One type projectile used fits into a regular gun-perforator cannon. Another projectile used is placed in an aluminum oversized sleeve and fired from the large diameter cannon of the sample-taker gun. In this manner, either type of gun may be used according to field conditions. These projectiles are shown in Fig 1.

The assembly containing the detector for the radioactive markers is made up of a number of sections suitably coupled mechanically and electrically. The lower section contains a casing-collar locator including a bottom-hole indicator. Next

is the radioactive marker-detector sonde. Occasionally a weight may next be used between the detector and the fishing head at the top. The outside diameter of this

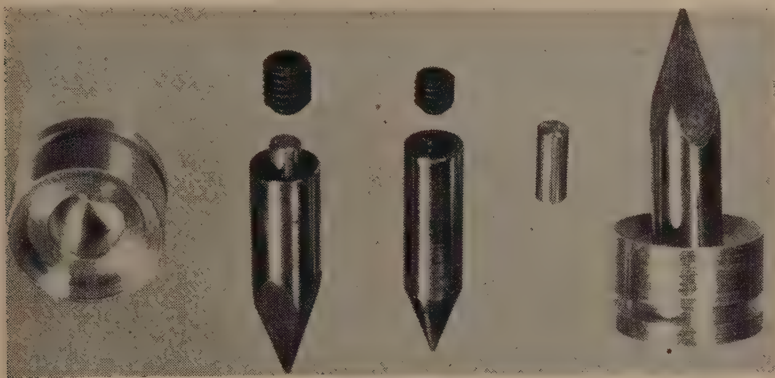

FIG 1—PROJECTILES.

Reading right to left: projectile made up with sleeve for sample-taker gun; small brass pellet containing radioactive salt; projectile used with gun perforator; projectile used with sample-taker gun showing pellet inside and retaining plug; aluminum sleeve.

equipment is 3½ in., while its overall length, without a weight, is 8½ ft. Fig 2 shows the apparatus made up.

When the sensitive element in the sonde passes by a marker in the hole, a sharp deflection occurs on the meter and a peak is recorded on the photographic log. It will then be a very simple operation to position any tool, which can be attached to the cable conjointly with the radioactive detector, at a given depth computed from the location of the marker. Usually the casing-collar locator is connected to the detector sonde so that the position of the radioactive marker and the position of the casing collars, which will be passed by the assembly, are recorded on the same film. The apparatus has been subjected to extensive field use for over two years. It has operated successfully under conditions in a borehole at a temperature over 300°F and at hydraulic pressures approximately 12,000 psi.

Field Technique

1. *Placing the radioactive marker*—The radioactive markers are usually placed immediately following the electrical logging survey. The geologist at the well, after comparison of the electrical log with his core record, frequently finds it advisable to supplement his data by taking some sidewall cores.[3] In the cases where the operator also desires to use markers, both the taking of cores and the placing of radioactive markers can be accomplished during one round-trip in the hole. A combined run of that type is becoming standing operating procedure in the completion of a well by many operators.

The sections where markers should be placed are to be determined considering not only the immediate zone to be tested, but also all other zones, elsewhere in the hole, which show production possibilities. The number of markers, their approximate interval and the type of formation in which to place them are next considered. The proper procedures vary with the field and the geological strata. Wherever the formations are soft and the boreholes are rela-

tively free from cavities, as shown by a record of the hole size, for example, or from general knowledge, then placement of markers in shale is quite satisfactory. In other areas, however, where shales crumble easily in contact with mud of the borehole and give large cavities, placement in sands have proved best. A shaly break within the sand to be tested is a good place.

The powder charge in the sample-taker gun is usually ample to lodge the projectile in the wall of the borehole, even for limy formations. It has been found, however, that occasionally the use of a gun perforator for greater penetration of the projectile is required for some hard sands and limes.

For each zone to be tested, practice has indicated the advisability of placing three or more markers at short intervals over a section that straddles the zone. Their proper placement increases the likelihood that at least two will remain after casing has been set. This aspect is discussed further in the section on locating the markers.

In view of the importance of the marker position, a thorough study has been made to ascertain its reliability. Statistics were compiled on the results of placement. The collected data indicate that the proportion of markers lost during placement is about 1 in 20 for soft formations, while in harder formations the proportion lost may be higher.

Furthermore, during the early phases of experimental work, the placement of the markers was checked by several location runs before casing was set. Occasionally a marker was found to have moved where cavities were likely present. Other check runs have indicated that trips in the hole with drill pipe after placement will sometimes disturb the location of the marker. Accordingly, it is advisable, whenever possible, to place the radioactive markers just prior to the running of the casing in the hole.

FIG 2—ASSEMBLY CONTAINING DETECTOR FOR RADIOACTIVE MARKERS.

The section of the open hole chosen for the location of the radioactive marker is correlated with the SP (Spontaneous Potential) log. The projectiles are fired when the gun is in uniform motion. Since it is quite necessary to know exactly where the markers are placed, a log of the SP is taken during the operations. A break in the recorded curve of the SP is made at the moment the projectile is discharged, thus indicating the position of the SP electrode.

From a knowledge of the constant physical separation on the apparatus in the hole between the recording electrode and the cannon discharged, the engineer determines the actual depths of the markers placed with respect to the electrical log. An illustration of an SP log made during such an operation is given in Fig 3. Breaks on the curve occur at 9945½ ft and at 9979½ ft, showing the position of the markers to be at 9966 ft and at 10,000 ft. The first marker at 9966 ft is in the shaly section above the sand while the second marker is in the sand body. The positions of the markers are then entered on the original log and thus become a permanent record in the company's files.

2. *Locating the radioactive markers*—The location of the markers is a separate operation made usually after casing has been set, often in conjunction with a gun-perforating job. It involves the detection of

the markers and their correlation with the depths of the casing collars in the vicinity of their placement.

The radioactive marker detector has been designed to be sensitive principally to strong localized sources of radioactivity. The sensitivity of the detector is relatively low; it is adjusted by means of a standard radioactive pellet at the surface, prior to the survey. At that low sensitivity, the natural gamma radiation from the formations will not be recorded on the film.

The low sensitivity, together with the small size of the sensitive elements of the detector sonde, compared to the characteristics of the usual gamma-ray logging apparatus, permits the positive identification of a marker and allows its position in the well to be determined sharply.

To have good accuracy, a low recording speed is used; it is usually of the order of 1500 ft per hour over the section of the hole wherein the markers and casing collars are to be found. The recorded section being generally short, this low speed does not appreciably increase the time necessary for the operation. The major part of the time of a survey is spent going down to the section of the hole to be logged and then bringing the apparatus back up to the surface. The elapsed rig-time may vary from 1 to 2½ hr for a complete operation.

The shape of the recorded trace for locating the marker is determined, among other things, by the recording speed and by the characteristics in the detector circuits. In the instruments used in the field, the characteristics have been chosen to give a sharp peak on the film as the sonde passes by a marker, thus permitting the marker to be ascertained accurately. At a recording speed of 1500 ft per hour, and for a survey made coming up the hole, the position of the marker is 6 in. below the point midway between the steep portions of the recorded trace.

The depths obtained during the location of the markers are given in reference to the SP curve of the electrical log used during placement. The position of each marker relative to the electrical log and

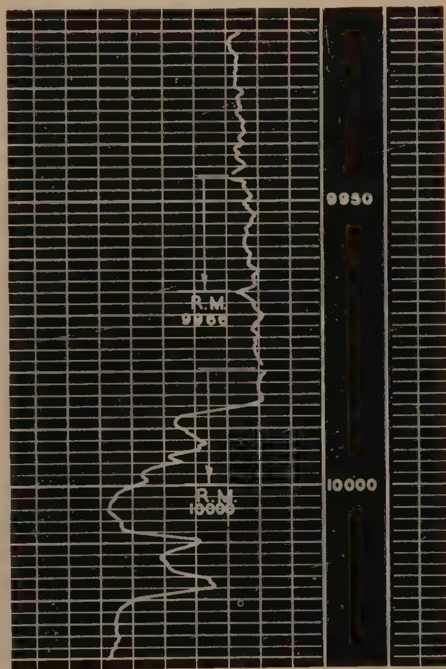

FIG 3—PLACEMENT OF RADIOACTIVE MARKER BY SP LOG.
R.M. 9966 and 10000

thereby to the geological column is fixed as a primary reference point available throughout the production history of the well.

An important measurement is the interval between markers. Where three or more markers are located after casing has been set, a comparison of the relative separations between each with their separations at placement will permit the operator to determine if any have subsequently moved. If one marker has moved, its amount and direction of displacement can definitely be determined from the other two undisturbed markers, regardless of their absolute depth. If only two markers remain, with their separation the same as at placement, then the likelihood is

that neither has moved from their point of placement with respect to the electrical log, for otherwise it would be necessary for both to have been displaced the same amount in the same direction during the period of time between placement and location.

From the foregoing discussion the conclusion is that each marker of any two that have retained the same interval is obviously at its original position. In order to be reasonably certain that two undisturbed markers remain, it is considered desirable to place three or more throughout each of the zones likely to be tested.

In order to give further reference standards, the positions of casing collars with respect to the markers are also logged over the important section of the hole. That information is desired by the operators whereby they may later make use of the casing collars as a check on their own casing measurements and also to position tools with respect to a formation, if later tests have to be made.

Application

Radioactive markers are being used at present in connection with several types of problems where the question of accuracy in depth measurements is important. In this connection, many production engineers will recall instances where difficulties arose after the well was cased; difficulties which could have been eliminated by the use of a dependable depth reference-point. Illustrations of the employment of radioactive markers are all instances of the general requirement that the well be tested or completed from a specific section in the borehole. The specific section picked for completion in the oil column is frequently critically determined by the location of the oil-water and oil-gas contacts.

In one case a field under a water drive has a producing zone in which the permeability of the formation in a vertical direction is quite low and variable. The horizontal permeability is appreciably greater. The formation is perforated selectively only a few feet at a time at the bottom of the sand just above the water level. In this way, trapping of some oil in a lower stratum is less likely to occur, as compared to completion initially by production over a long vertical zone. When the well becomes noncommercial, then it is squeezed with cement and reperforated in the next short interval, using a radioactive marker as a reference point for the series of operations. Tubing measurements thereby need be relied upon only as a gross check. Furthermore, regardless of any later changes of equipment above the ground, such as a new derrick floor, a permanent and consistent reference point is now available for depths within the well bore.

In another field it was found that wells completed in the oil column above a thin shale streak about 1 ft thick gave appreciably higher gas-oil ratios compared to those completed below the streak. The use of radioactive markers as reference points provided the necessary assurance that all perforations were made below this break, compared to the earlier practice of using depth measurements from a reference point at the surface. The subsequent improved gas-oil ratios were evidence of successful completion where markers were used.

Other cases occur frequently, such as, where the electrical log indicates that a thin sand streak, with good production possibilities, needs to be tested, or where the efficient placement of perforations is required for a cement squeeze job at the water-oil contact in a producing horizon.

The following summary will indicate the type of problems wherein the markers have been used in cased holes:

1. Correlation of a definite point in the well bore with the formations on the electrical log.
2. Production from specific zones within the oil column, and in known relation to any oil-gas or oil-water contacts.

3. Perforations for cement squeeze jobs opposite:
   a. oil-water contact
   b. oil-gas contact
   c. specific formations.
4. Increased efficiency in placement of perforations for zones to be tested.
5. Testing and production from thin beds at great depths sub-surface.
6. Constant reference point for use in work-over of wells, regardless of subsequent changes in surface equipment.
7. Permanent markers, which are indicated on the electrical log, as insurance against loss of other well records.

Field Examples

The illustrations in Figs 4 and 5 are given as examples to show the use of radioactive markers to assist in the solution of some production problems. These illustrations are tracings of the radioactive-marker log, casing-collar log, and of the electrical log recorded over the same section of the

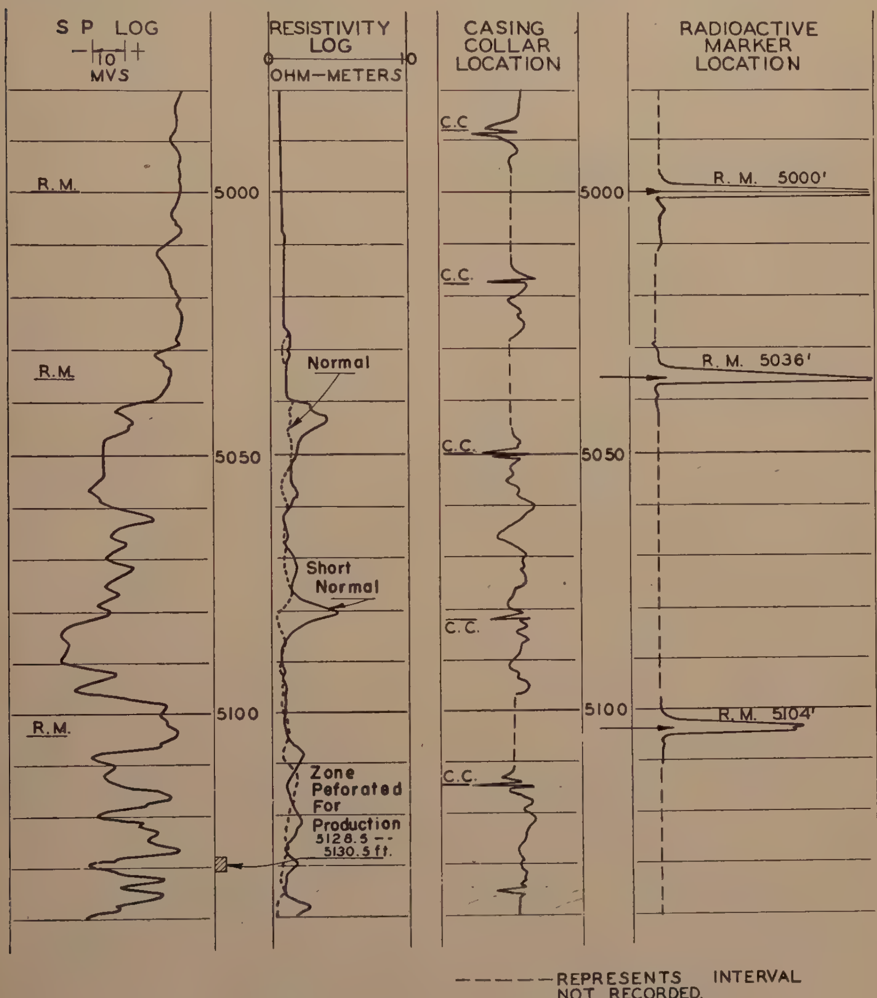

Fig 4—Drill-stem tests using radioactive markers.

hole. The positions where the radioactive markers (RM) were placed are indicated on the SP log. It can be seen that the location of the markers and the casing joints are definitely tied into the position of any strata in the borehole.

permits a depth discrimination in perforating, for example, which is much beyond that obtainable if the derrick floor were used as the sole reference plane for depth measurements.

In the well illustrated by Fig 4, drill-stem

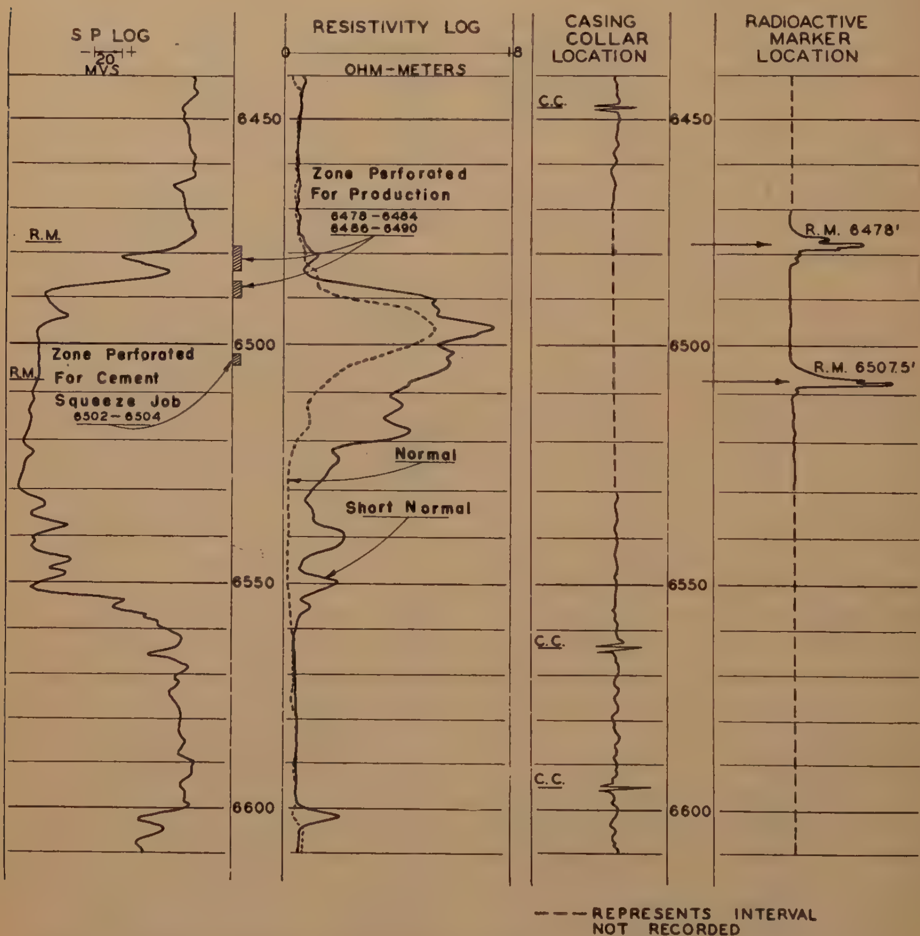

Fig 5—Use of radioactive markers for efficient placement of perforations.

The radioactive-marker survey logs are recorded such that the depths on the logs correspond to the position of the sensitive element of the radioactive-marker detector. The markers are thereby at a position corresponding to the depths of their deflections on the log. This knowledge

tests in open hole from the section around 5050 ft gave dry gas, while a test in the interval from 5131 to 5135 ft gave a mixture of oil and water.

After consideration of the electrical log and the results stated, the company decided to perforate an interval of 2 ft from 5128.5

to 5130.5 ft on the electrical log. They desired to avoid perforating lower than 5132 ft or higher than 5127 ft.

Three radioactive markers were placed in the formation at depths corresponding to 5000, 5036 and 5104 ft on the log. Thus, the marker at 5104 ft was 24½ ft above the top of the zone desired to be perforated, regardless of absolute depth measurements.

A comparison of the total depths measured during the electrical survey and the perforating operations is as follows:

TABLE 1—*Comparison of Total Depths Measured*

Company	Electrical Survey, Total Depth, Ft	Gun Perforation, Total Depth, Ft
Schlumberger......	5140	5139
Driller...........	5142	5135

Since the difference of 4 ft in total depth during the perforation operation was in opposite sign to that which would occur if the bottom of the casing had settlings, there was a real difference in measurements. This was quite important as a difference of only 2 ft would miss the sand zone. Moreover, no reconciliation would be possible between the relation of the depths in the cased hole and the formation to be perforated without the use of a common reference point such as is provided by the radioactive marker at 5104 ft. on the electrical log.

Using the radioactive-markers to position the gun, the zone was perforated with eight shots from 5128.5 to 5130.5 ft. The well came in at 170 bbl per day with a gas-oil ratio of 400 to 1 on a 19⁄64-in. choke.

The example in Fig 5 also shows the use of radioactive markers for efficient placement of perforations.

Perforations were first made over the interval of 6502 to 6504 ft, using the marker at 6507.5 ft. Cement was then squeezed through these perforations to be certain of a seal-off from the water in the sand below this interval.

Perforations for production were then made in two sections at depths of 6478 to 6484 ft and 6486 to 6490 ft. The use of the radioactive markers allowed perforations within the shaly interval from 6484 to 6486 ft to be omitted.

The well came in with initial production of 180 bbl per day with a gas-oil ratio of 300 to 1 on a 9⁄64-in. choke.

CONCLUSION

The increased need for better depth discrimination, particularly for the deeper horizons, may be satisfied through the use of radioactive markers placed at chosen points in the wall of the borehole with respect to known strata.

Successful apparatus for the detection of such radioactive markers has been designed to be lowered in the borehole and withstand the highest temperatures and pressures encountered. The operation of the apparatus is safe, reliable and does not require any appreciable rig time.

Radioactive markers assist the production engineer in the solution of problems involving depth measurement met during testing, production and remedial workover jobs. These markers, being placed in a known relationship to a given geological horizon, permit the accurate positioning of tools in the cased well with respect to formations previously located by an electrical log, regardless of the depth of the formations from the surface. The markers also become part of the well record as primary reference points for future production problems throughout the history of a well, regardless of changes in reference points with respect to surface equipment.

ACKNOWLEDGMENTS

We wish to acknowledge the kind cooperation of F. M. Boykin, Jr., Carleton B. Wood, Lynn Oil Co. and others whose courtesy made available examples of actual radioactive-marker surveys in the field.

We also appreciate the advice and suggestions of our co-workers, Mr. J. A. Bodin and Mr. W. B. Steward, who developed the radioactive-marker detector equipment, and Mr. H. C. Fagan, who developed the instrument used for the casing-collar locator.

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Use of Oil-emulsion Mud in the Sivells Bend Field

By W. H. Echols*

(New York Meeting, March 1947)

Abstract

An oil-emulsion mud, consisting of a mixture of oil-base mud and bentonitic water-base mud, has been used experimentally in drilling 8 of the 35 wells in the Sivells Bend field, Cooke County, Texas. Experience indicates the oil-emulsion mud can be controlled in much the same manner as a water-base mud, and the "drilling" functions of the two types of mud are comparable. The average water-loss for the oil-emulsion mud was 3.8 cu cm per well. When using oil-emulsion mud to drill the last 2000 ft of 7000 ft wells, the mud costs were approximately 2½ times that of water-base mud. There is nothing to indicate well productivities have been affected through the use of oil-emulsion mud. However, drilling time and bit footages were increased and the holes were maintained more closely to bit guage. The apparent advantages gained through the use of oil-emulsion mud in the Sivells Bend field do not appear to justify the increase in mud costs.

Introduction

Until a comparatively few years ago most of the development of drilling mud was directed toward improving the functions of the mud as related to actual drilling operations. The industry has long recognized that one disadvantage of rotary drilling over cable-tool drilling is the possibility of injury to producing zones through the blocking effect resulting from the infiltration of water or mud into the sands. Recognizing this disadvantage, considerable attention has been diverted toward the development of muds that will improve the quality of well completions through the reduction or elimination of water into the sands, but without sacrificing too many of their "drilling" functions and at a cost commensurate with the benefits derived from their use. This phase of mud research has already found practical application, for example, in the development of the Rangely field, Colorado, it appears the use of oil-base mud during drilling-in operations will contribute appreciably toward making this exploitation more profitable.

Much of the discussion to follow will be better understood if a brief sketch of the Sivells Bend field is given. The Sivells Bend field, discovered by The Texas Co. in 1944 and still in the process of development, is in a large bend on the Texas side of the Red River about 85 miles north of Dallas. Geologically, the structure is an unsymmetrical anticline, with faulting having contributed to its development. The productive sands are of the Strawn series of Pennsylvanian age, the sands being lenticular in character and varying considerably in development from well to well. At present there are 35 producing wells in the field, producing from seven different sand lenses. The productive sand lenses vary from 15 to 50 ft in thickness and the individual sands have average permeabilities of from 75 to 375 md. The presently productive sands are encountered at depths of from 6300 to 7300 ft, but testing has indicated that commercial production might be obtained from other sands as high as 5200 ft. Histories of older Strawn

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sand fields in North Texas indicate that they are rather consistently of the dissolved gas-drive type, resulting in short flowing lives, comparatively long pumping lives and low ultimate recoveries. In addition, many Strawn sand wells require considerable swabbing at completion, possibly resulting from one or more of these causes: low reservoir pressures, low sand permeabilities, or water-blocking occuring during drilling operations.

Early in the life of the Sivells Bend field, it became apparent that it would follow the typical pattern of other Strawn sand fields, and in an effort to effect better well completions, it was decided to use a low water-loss mud in several wells. As previously stated, the productive sands vary from 6300 to 7300 ft, with productive possibilities as high as 5200 ft, a condition which would necessitate drilling over 2000 ft of section with the low water-loss mud if all of the sands were to be protected. Laboratory work, together with limited field application, indicated that an oil-emulsion mud, controlled in much the same manner as a water-base mud, could be maintained with a 2 cu cm or less water-loss at an estimated cost that appeared to justify its use. The oil-emulsion mud was adopted on somewhat of an experimental basis, being used initially to recomplete two wells drilled with a water-base mud. Later, on all wells to be drilled with oil-emulsion mud, a standard procedure was adopted whereby each well was drilled to a depth of approximately 5000 ft with a water-base mud, then the mud was converted to an oil-emulsion mud which was used until the well was completed.

The oil-emulsion mud as herein discussed is a mixture of 18 to 25 pct by volume of a commercial oil-base mud, with the remainder of the mixture being bentonitic water-base mud. The oil-base mud used was composed of blown asphalt, diesel oil, sodium chloride, caustic soda, sodium silicate and tall oil as the active ingredients.

Control of the Oil-emulsion Mud

The control of the mud down to a depth of approximately 5000 ft was in charge of a representative of a mud concern marketing commercial drilling muds and chemicals. As the drilling approached 5000 ft a concerted effort was made to lower the water-loss to about 10 cu cm, and to condition the mud properly for the addition of the oil-base mud. At the time the oil-base mud was added to form the emulsion, the control was turned over to a representative of the concern marketing the oil-base mud, and this representative was given a free hand to control the mud according to his own judgment. This procedure was deemed advisable inasmuch as it appeared the control would then be under the supervision of more thoroughly trained and experienced personnel. And after drilling eight wells with the oil-emulsion mud, it does not appear that any deficiency in control can be attributed to the lack of diligent supervision.

No extra equipment was used in these operations, other than providing a 210-bbl welded tank at each well for storing the oil-base mud. Ordinary earthen mud pits were used. The oil-base mud was usually injected into the pump suction as drilling proceeded and the mud made a complete circulation through the well before going into the pits. A rather slow but efficient method of injecting the oil-base mud into the system was through an improvised jet made out of a 55-bbl oil drum. On the initial treatment, oil-base mud was added in an amount approximating 25 pct of the mud system. Experience has proved that the control of the oil-emulsion mud is similar to that of water-base mud—the two types of mud respond to chemical treatment similarly and are likewise contaminated by formation water in the same manner. Fresh water does not affect

the emulsion mud other than to lower the viscosity and increase the water-loss when added in amounts exceeding that necessary to hydrate the gels.

Since some of the oil-base mud clings to the cuttings and settles out in the pits and some is lost through that part of the hole drilled with water-base mud, by the time a well is completed it has been necessary to add oil-base mud in excess of 25 pct of the maximum volume of the mud system. The small particles of weighting material have an affinity for the oil-base mud, and if contamination results in sufficient loss of gels as to cause the oil-coated weighting material to drop out, the water-loss increases rapidly and rather lengthy and expensive treatment is necessary to restore a low water-loss. Sand does not appear to settle out of the oil-emulsion mud as readily as it does from a water-base mud and for this reason gunning pits is held to a minimum, which adds somewhat to the difficulty of control. It is believed that the functions of the oil-emulsion mud as related to drilling operations are comparable with those attained with a water-base mud. However, since a low water-loss was the primary objective, it is interesting to note the results obtained: on eight wells drilled with the oil-emulsion mud, the average water-loss per well varied from a low of 2.7 cu cm to a high of 5.1 cu cm, with the eight wells having an average water-loss of 3.8 cu cm. In practical application it has not been found possible to achieve the low water-loss indicated by laboratory work, but this condition is a normal expectancy in the early stages of the development of most products.

Effect of Oil-emulsion Mud on Drilling Operations

When oil-emulsion mud was first introduced, there was a definite lack of enthusiasm on the part of the drilling crews toward its use. It was more difficult to keep the equipment clean, it increased their work to some degree and it was something new. However, after the first few wells, the crews had become more familiar with its use and the conversion from water-base mud to oil-emulsion mud was accepted as a routine operation. It was not deemed necessary to expand existing fire-prevention rules when the use of oil-emulsion mud was initiated, since the only additional fire hazard resulted from storing the oil-base mud adjacent to the rig.

Initially, conventional rubbers were being used for pump pistons and valves, and pump-maintenance costs increased appreciably until oil-resistant equipment was substituted. In order to reduce sand cutting in the pumps it was necessary to increase the length of the settling pits. These changes, together with some experience in preventative pump maintenance resulted in reducing the pump costs to a figure only slightly higher than when using a water-base mud.

The comparative effect of sand-cutting on the tool joints could not be determined since both types of mud were being used. After changing from a water-base mud to an oil-emulsion mud, one contractor observed there was approximately one-eighth less horsepower consumption while rotating the drill pipe. This observation indicates that less torque is transmitted to the drill pipe, which should tend toward reducing fishing jobs resulting from drill-pipe or drill-collar failures. Although there are no factual data to substantiate the opinion, it is believed that drill pipe will give longer service when an oil-emulsion mud is used.

The use of oil-emulsion mud appears to increase the drilling rate and bit footage. Table 1 is presented to show the comparison of drilling rates and bit footages of wells using the two types of mud. Since the emulsion mud was introduced at approximately 5000 ft, the data were

segregated into two parts: from beneath the surface casing to approximately 5000 ft and from 5000 ft to total depth. Rock bits were used exclusively from surface to total depth on all wells. It is interesting that the drilling rates in the top sections of the wells are so extremely close, but no explanation can be given for the variance in bit footages. Below 5000 ft both the average drilling rate and the average bit footage of wells drilled with oil-emulsion mud exceeds those of wells drilled with water-base mud.

TABLE 1—*Comparison of Drilling Rates and Bit Footages with Two Types of Muds*

Number Wells	Type of Mud Used	Hole below Surface Pipe, to 5000 Ft		Hole from 5000 Ft to Total Depth	
		Avg Drilling Rate, Ft/Hr	Avg Bit Footage, Ft/Bit	Avg Drill-Rate, Ft/Hr	Avg Bit Footage, Ft/Bit
8	Oil-emulsion	9.18	190	5.68	146
7	Water-base	9.19	229	4.95	119

The Sivells Bend field has not presented any very troublesome drilling problems such as crooked holes, heaving or sloughing shales, tight holes, or sources of high pressure gas, so it is rather difficult to analyze what affect the use of oil-emulsion mud might have toward alleviating or multiplying problems resulting from these conditions. It has been possible to drill with more weight on the bit without increasing the danger of crooked holes, and the few fishing jobs that have occurred have been readily cleaned up in a minimum of time. The holes stand up exceptionally well, and as a result casing is landed freely and no trouble is experienced in making trips.

EFFECT OF OIL-EMULSION MUD ON COMPLETION PROBLEMS

When the use of oil-emulsion mud was under consideration, one of the most prevalent questions arising in the minds of those charged with following drilling progress on the wells, was whether or not the oil-base phase would alter the appearance of the well cuttings sufficiently to result in misinterpreting the fluid content of some of the sands. In application, it has been found that the oil-base phase does induce slight false staining and florescence, but this effect is lessened by carefully washing the samples. After gaining a little experience, the difference between the true and induced characteristics became readily discernible, and it is doubtful if any misinterpretations resulted therefrom.

Core recoveries in the Sivells Bend field have been in the order of 95 to 100 pct regardless of the type of mud used. Core analysts find that cores cut with oil-emulsion mud are as completely flushed as if clear water had been used as the drilling fluid, and they report that there is no perceptible difference in the appearance or interpretation of the cores, as compared with those taken in water-base mud.

Caliper logs indicate that the wells drilled with oil-emulsion mud have approached bit size more closely than have wells drilled with water-base mud. Fig 1, comparing caliper and electric logs of wells drilled with the two types of mud, has several interesting features: (1) the comparative deviation from bit size of the two wells, (2) that although the oil-emulsion mud was introduced in Well "A" at 5051 ft, the hole above that point was maintained approximately to bit size and (3) the similar characteristics of the caliper log and the potential curve of the electric log on Well "B." It is reasonable to assume that a hole more closely approximating bit size will result in a better cement job, but in this instance available data neither proves or disproves this assumption.

Electric logs taken in oil-emulsion mud vary from those taken in water-base mud in these respects: (1) the self-potential and short-normal curves are flattened, but the long-normal or lateral curves are not noticeably affected, (2) the less permeable sands are not so easily discernible and (3) the value of the self-potential curve is destroyed in so far as determining relative permeabilities. However, for correlative purposes electric logs obtained in oil-emulsion mud appear equally as good as those obtained in a water-base mud, as illustrated by Fig 2, which is a section through two wells in which oil-emulsion mud was used and one well in which water-base mud was used.

Fig 3 illustrates the changes occurring in electric logs between subsequent surveys taken at different depths during the course of drilling a well. Although the most noticeable change is the "growing" of the normal curve, this effect is actually less than is indicated by similar electric logs taken in wells drilled with water-base mud. The flattening of the potential and normal curves is visible, but closer scrutiny is necessary to detect the small amount of infiltration indicated by the inward shifting of the lateral curve.

The use of oil-emulsion mud has not

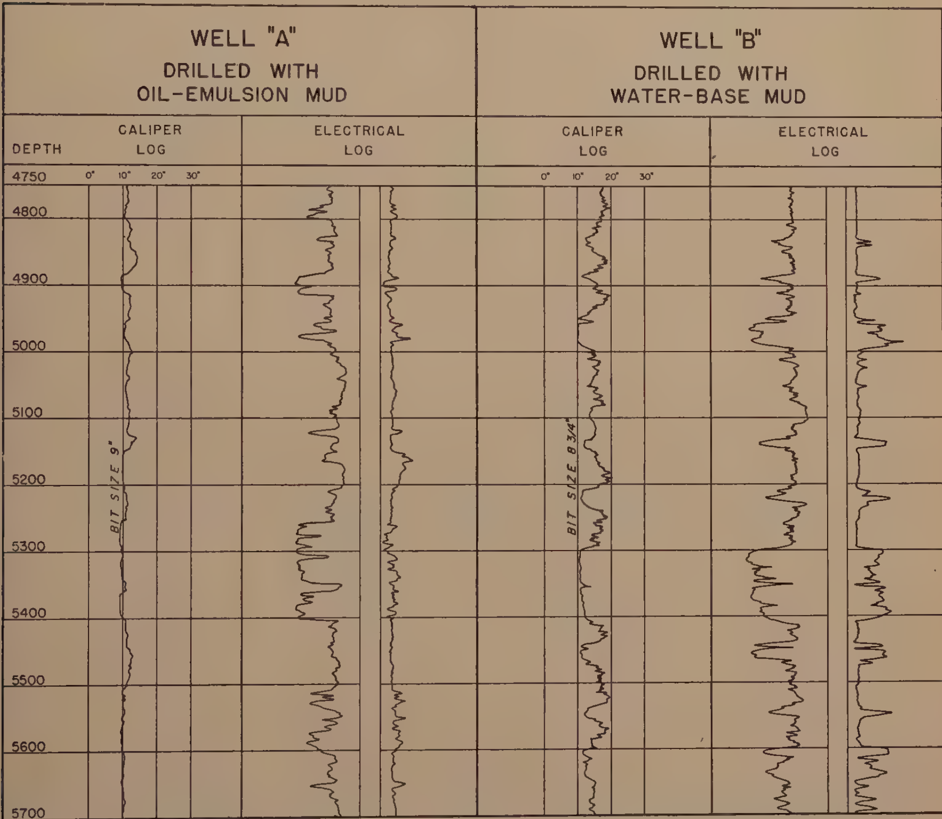

FIG 1—COMPARING CALIPER AND ELECTRICAL LOGS OF WELL DRILLED WITH OIL-EMULSION MUD VS WELL DRILLED WITH WATER-BASE MUD.

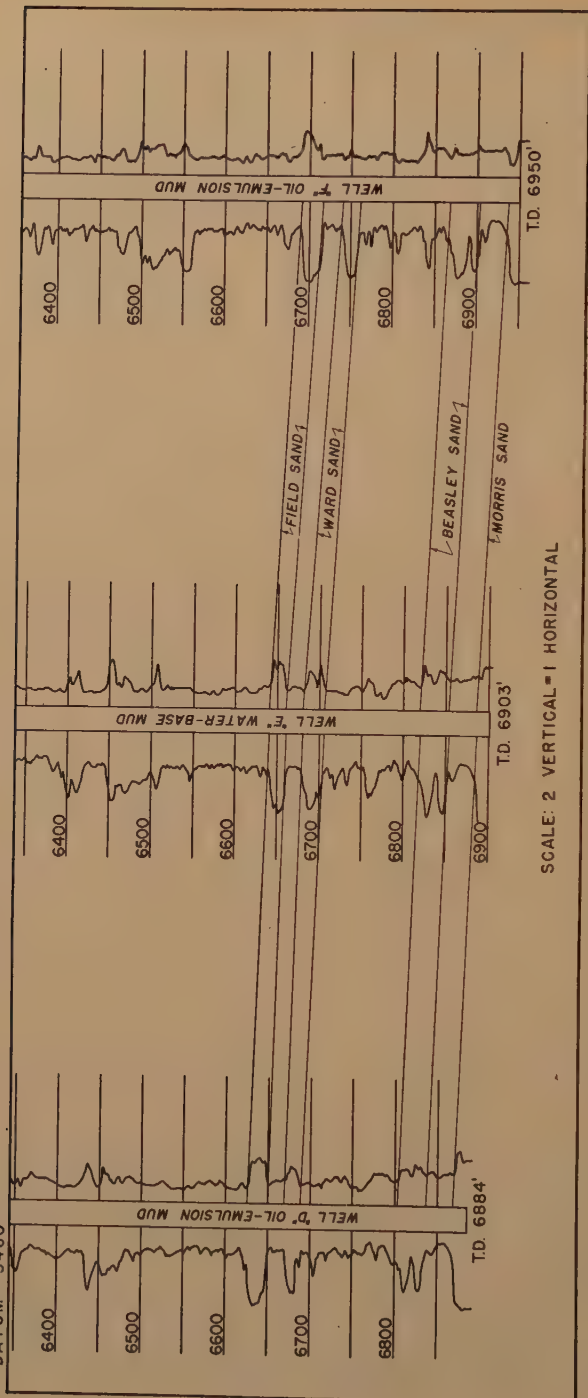

FIG 2—CORRELATION SECTION. COMPARING ELECTRIC LOGS OF WELLS DRILLED WITH OIL-EMULSION MUD AND WATER-BASE MUD. SIVELLS BEND FIELD, COOKE COUNTY, TEXAS.

Fig 3—Changes in characteristics of electric logs during subsequent runs in same well, using oil-emulsion mud.

noticeably affected the mechanics or results of squeeze cementing. The percentage of failures in open-hole drill stem testing has been greater in those wells using oil-emulsion mud but data are insufficient with which to compare the results on testing inside casing. When perforating casing with an electrically-operated gun, the percentage of "duds" will increase unless the shell chambers are carefully cleaned out before reloading.

Of the eight wells drilled with oil-emulsion mud, five have required swabbing at completion. It has been noticeable that these wells have required less swabbing and they cleaned up much more readily than did wells drilled with water-base mud; but it is believed that this can be partially explained by the fact that at completion, the oil-emulsion is displaced with oil and the water-base mud is displaced with water.

Comparative Mud Costs

In an effort to reduce mud costs, whenever possible the oil-emulsion mud was transferred from well to well, but of the original volume of oil-emulsion mud on a well, only about 50 pct was transferable, with most of the lost mud being left behind the oil string, some being contaminated during the well completion, and with additional losses incurred in jetting pits. It is questionable if transferring the emulsion mud actually resulted in reducing costs, since in some instances the transferred mud did not readily combine to form a true emulsion with the water-base mud to which it was added, a condition which necessitated additional treatment. Also, the highest average water-losses were obtained on wells using transferred oil-emulsion mud.

The average mud costs of eight wells drilled with oil-emulsion mud was approximately 2½ times the average mud costs of nine wells drilled with water-base mud. The mud costs for the eight wells drilled with oil-emulsion mud actually represented the costs for drilling approximately 5000 ft of hole using water-base mud and approximately 2000 ft of hole using oil-emulsion mud. Also, of the mud costs for the wells drilled with oil-emulsion mud, 53 pct was for the oil-base material, the remainder for other mud and chemicals. The additional cost resulting from the use of oil-emulsion mud, amounts to approximately 4 to 5 pct of the per well development cost.

Effect of Oil-emulsion Mud on Well Potentials

It is believed that any comparison of the capacity of wells to produce can best be effected through the use of productivity indices, and it is unfortunate that data are insufficient to make such a comparison here. However, Table 2 compares the average potentials of wells drilled with oil-emulsion mud with those drilled with water-base mud. The conditions under which these potentials were taken are at considerable variance. Some of the potentials were necessarily taken on the pump, whereas, on the flowing wells, choke openings varied from ¼ in. to open flow through 2½ in. tubing. But it is doubtful if the disparity in choke openings actually influences this comparison appreciably, since averaging should tend toward balancing the results. Further, careful observation has indicated that most of the wells appear to have critical choke openings, usually in the range of ¼ in. to ¾ in., which afford maximum production rates—increasing the choke openings above this point on a well usually results in intermittent flow with a decrease in production. The comparison of "wells completed on the pump" and "wells perforated in more than one interval" serves no purpose other than it might be some indication that the wells drilled with oil-emulsion mud actually occupied the most favorable structural positions. Of the ten wells

having the highest potentials in the field, two wells were drilled with oil-emulsion mud, those being second and ninth in descending order.

TABLE 2—*Comparison of Average Well Potential with Two Types of Mud*

Number Wells	Type of Mud Used	Wells Completed on Pump, Pct	Wells Perf. in More Than One Interval, Pct	Average Potential, Bbl per Day
8	Oil-emulsion	12½	75	466
25	Water-base	20	12	468

If the comparison of average well potentials is justifiable, the averages of the two groups of wells are so close as to indicate that the quality of well completions in the Sivells Bend field has not been materially influenced by the type of drilling mud used.

CONCLUSIONS

There are no data or observations to indicate that the use of oil-emulsion mud in the Sivells Bend field has contributed toward any improvement in the productivity of the wells in which it was used. That there were no discernible benefits, may be attributable to one of these reasons: (1) infiltration of fluids into the sands while drilling may have been of no consequence, since the sand permeabilities were sufficiently high as to permit the infiltered fluids to be flushed from the sands once the wells were placed on production, or (2) the magnitude of the water-loss of a mud may not be the controlling factor, but the presence of any degree of water-loss will just as effectively result in "blocking" sands within certain ranges of permeabilities and pressures.

Most of the apparent advantages gained through the use of oil-emulsion mud were related to actual drilling operations, in increasing drilling time and bit footage and the indicated longer service from drill pipe. However, it does not appear that these benefits justify the additional cost of the mud.

It is not believed that the use of oil-emulsion mud should be condemned solely on the apparent lack of application in the Sivells Bend field. It is believed that additional experience must be gained in controlling oil-emulsion mud so the resulting cost may be lowered to the point that its use is more easily justified. Additional research and development might disclose that this mud has many practical applications. The use of oil-emulsion mud might have application where certain types of heaving or sloughing shales create difficult drilling problems, since caliper logs indicate the well bore stands up exceptionally well through shale sections.

ACKNOWLEDGMENT

The author wishes to express his appreciation to the Standard Oil Company of Texas for permission to prepare and publish this paper; to Mr. C. W. Reith and Mr. R. W. Harrison for their constructive criticisms; to the operators, drilling contractors and service companies for contributing data and helpful discussion; and to all of the Standard Oil Company of Texas, North Texas District personnel, whose many suggestions made this presentation possible.

Cathodic Protection of Steel Tank Bottoms by the Use of Magnesium Anodes

By J. R. James* and R. L. Featherly†

(Galveston Meeting, October 1946)

Abstract

The replacement or reconditioning of oil storage tank bottoms due to external corrosion is an expensive maintenance item to the oil industry.

Cathodic protection as a means of mitigating this problem has proved very successful in the past few years.

One pipe-line company recently used magnesium anodes to cathodically protect two 55,000 bbl and two 20,000 bbl tanks. The tank bottoms were protected as individual units with considerable factual data being taken on one of the 20,000 bbl tanks. Twelve 60-lb anodes were installed about 2½ ft from the tank on approximately 17-½ft centers around the tank.

Previous installations and tests have shown that sufficient protection is provided when the tank-to-soil potential using a copper-copper sulphate half-cell as a reference electrode is −0.90 volts at the edge of tank.

Potential measurements taken a few months after completing the installation indicated that the potentials were higher than were needed for protection. Resistors were then inserted in the individual anode circuits which increased the life of the anode installation and still provided adequate protection for the structure.

All connecting pipe lines were then insulated from the tank. This limited the anode current strictly to the tank resulting in a greater degree of protection with a still longer anticipated anode installation life.

The total installation cost for this tank was less than $300 which amounts to $20 per year based on an expected installation life of 15 years. This figure represents an annual cost of one per cent compared to the cost of replacing the tank bottom.

The corrosion of metallic structures in contact with soil or water has been a very serious and costly problem for centuries. The annual loss to our nation's pipelines alone is estimated at $200,000,000. Mitigation of this problem by various methods has been carried on quite successfully for a number of years. An electrical method called cathodic protection has been used with considerable success to control corrosive influences on pipelines, tank bottoms, cable sheathing and other buried metal structures.

Corrosion of oil storage tank bottoms has been a serious problem among the oil industries for years. In addition to damage costs and loss of oil, the replacement of one tank alone represents several thousand dollars. A reconditioning program at periodic intervals was instituted by several organizations and found to be a very expensive process.

A few years ago two of the pipeline companies installed cathodic protection units at their tank farms.[3,4] The average current required for protection of the tank bottoms varied from 0.7 to 1.0 milliampere per square foot. The results indicated that adequate protection was obtained at a cost of approximately 10 pct of the previous reconditioning program.

The Republic Pipe Line Company experienced severe corrosion on their oil storage tanks. One of their 55,000-bbl tanks

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[3] References are at the end of the paper.

had to be replaced at an approximate cost of $10,000 after only eight years of service. Various methods of mitigating this problem were investigated finally resulting in the use of magnesium anodes. Magnesium anodes were installed on two 20,000-bbl tanks and two 55,000-bbl tanks at their Welder pump station near Corpus Christi, Texas. A layout of the four tanks and some of the connecting pipe lines is shown in Fig 1.

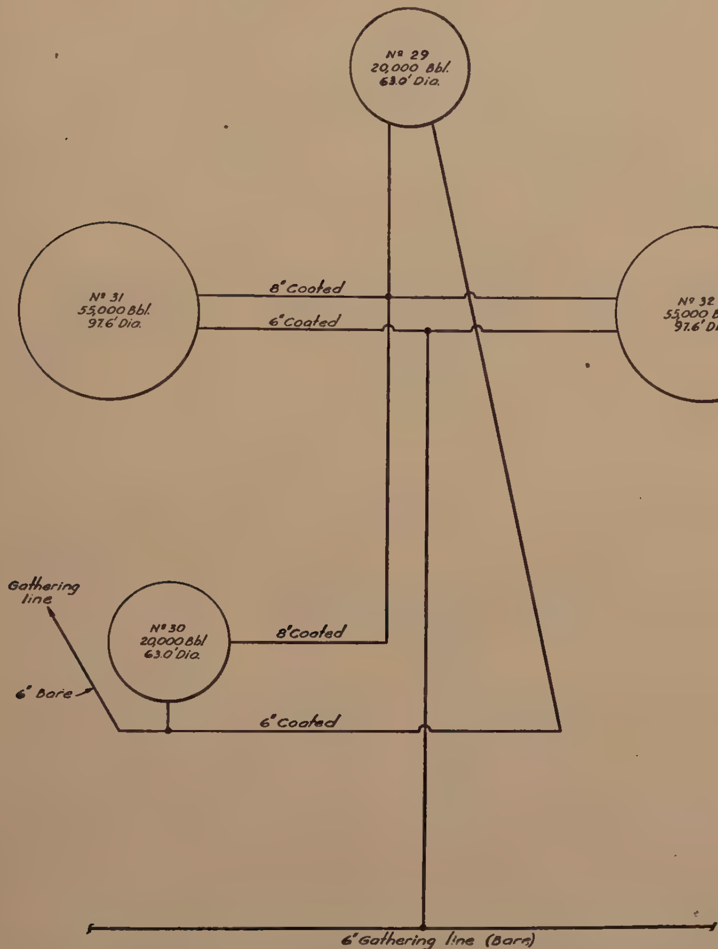

FIG 1—LAYOUT OF REPUBLIC PIPE LINE COMPANY'S WELDER STATION TANK FARM AT CORPUS CHRISTI, TEXAS.
Scale 1 inch = 80 feet.

Soil resistivity measurements made at prospective anode installations varied from 150 to 600 ohm centimeters. These resistivity readings indicated that a fairly high anode current flow would be realized. This resulted in the use of a 60-lb magnesium anode, 4 in. in diameter and 60 in. long, so that a long installation life would be realized.

The holes for the anodes were dug with a 6-in. hand auger to a depth of about 7 ft. The holes were spaced equidistantly around the circumference of the tanks and about

2½ ft out from the base as shown in Fig 2. Twenty anodes were installed on 16-ft centers on the 55,000 bbl tanks and twelve anodes on approximately 17½ ft centers to check corrosion, should be increased to −0.90 volt at the periphery to insure that the entire tank bottom is receiving adequate cathodic protection.

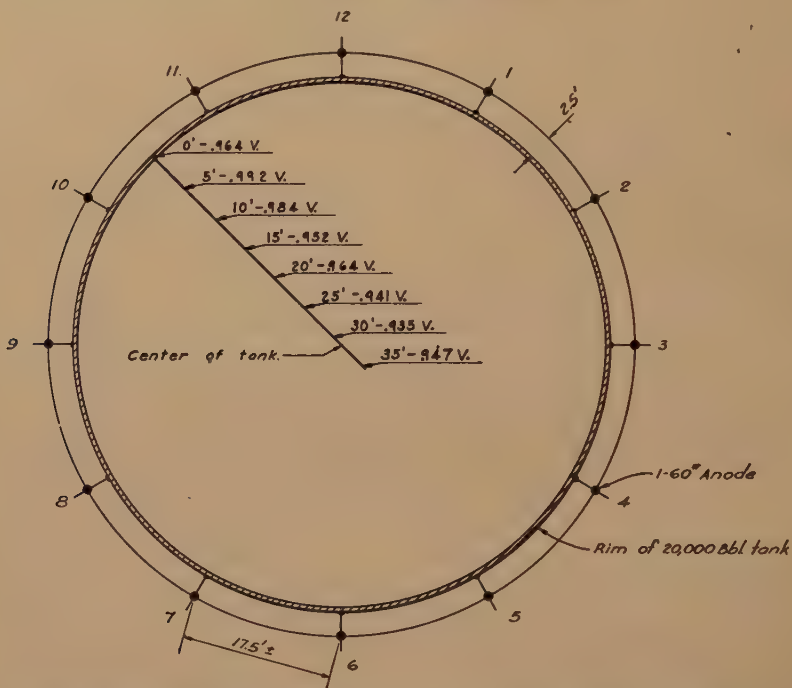

FIG 2—ARRANGEMENT OF MAGNESIUM ANODES ON 20,000-BARREL WELDER STATION TANK NO. 29.

on the 20,000-bbl tanks. The anodes were placed in the holes and surrounded with a wet backfill mixture consisting of 75 pct bentonite and 25 pct gypsum. The anode leads were bolted to the angle iron at the base of the tanks.

Previous installations and tests have shown that sufficient protection is provided when the tank-to-soil potential using a copper-copper sulphate half-cell as a reference electrode is −0.90 volt at the edge of the tank. Bond[8] observed from a series of potential measurements that the potential at the center of a 55,000 bbl tank bottom was 0.05 volt more positive than the potential of the metal at the perimeter of the tank. Therefore, the usual potential of −0.85 volt, which is considered sufficient

In order to eliminate as much repetition as possible, the installation details and factual data on only one of the 20,000-bbl tanks are described.

Magnesium anodes were installed on Welder station tank No. 29 in Dec., 1945. This tank has a diameter of 63 ft with approximately 3100 sq ft of surface in contact with the soil. Twelve 60-lb anodes were installed about 2½ ft from the tank and on approximately 17½ ft centers around the tank (Fig 2). Holes 7 ft deep were dug with a 6-in. hand auger. A thoroughly mixed wet backfill slurry consisting of 3 parts of bentonite clay and one part of gypsum was placed in the holes. Approximately 400 lb of backfill material was used for the 12 holes which is an

approximate weight ratio of 1 part of backfill to 2 parts of magnesium. The anodes were then placed in the holes in such a manner that the anodes were completely anode lead connections to the tank and midway between these anode connections. These readings ranged from a minimum between the anode connections of

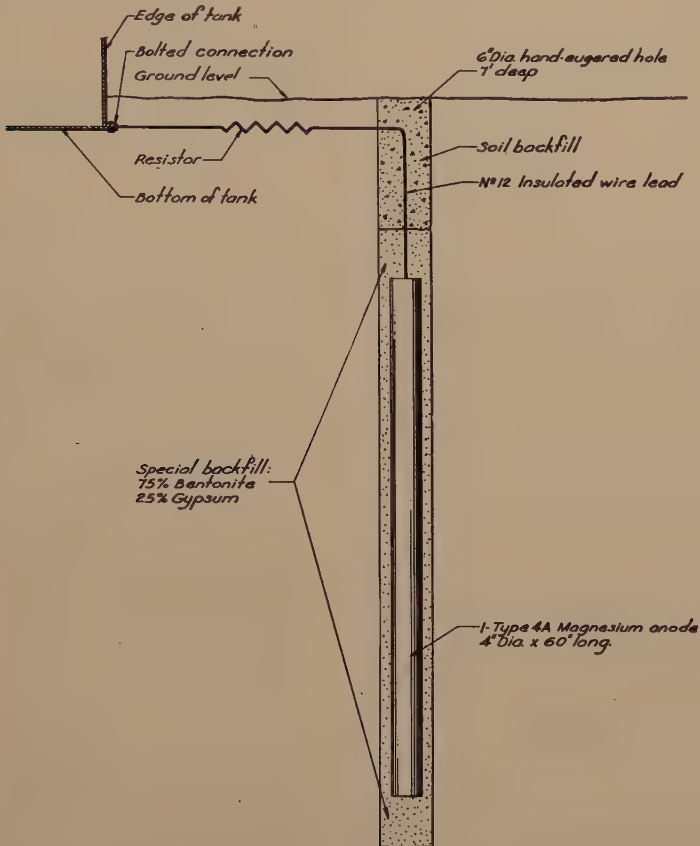

FIG 3—DETAILED CROSS SECTION OF MAGNESIUM ANODE INSTALLATION ON OIL-STORAGE TANK.

surrounded with this backfill mixture. The copper wire anode leads were attached to the tank by means of a small bolt as shown in Fig 3.

Tank-to-soil potential measurements were taken around the edge of the tank before the anodes were connected, using a potentiometer and a copper-copper sulphate half-cell as a reference electrode. These readings ranged from −0.66 to −0.74 volt. Three months after the installation was completed, tank-to-soil potential measurements were taken at the

−1.03 volts to a maximum at the connections of −1.21 volts. This tank bottom had been painted with an asphalt paint and placed on a 6-in. clean bank sand foundation at the time of the tank installation. These potentials were considerably higher than are necessary for complete protection. It was decided to lower these potentials by reducing the anode current flow. This was accomplished by inserting small resistors in the anode leads. Tank-to-soil potential measurements taken after the resistors were installed showed a minimum of −0.91

volt and a maximum of −1.05 volts. These values allow a sufficient margin for the voltage drop expected at the center of the tank.

TABLE 1—*Tank-to-soil Potential Measurements from Periphery to Center of Welder Station No.* 29

DISTANCE FROM PERIPHERY, FT	TANK-TO-SOIL POTENTIAL, VOLTS
0	0.964
5	0.992
10	0.984
15	0.952
20	0.964
25	0.941
30	0.935
35	0.947

Anode current measurements taken previous to the installation of the resistors ranged from 0.815 to 1.190 amperes, with a total output of 10.925 amp, or a current density of 3.5 ma. per sq ft of tank area exposed to the soil. The life of the installation with this current flow and based upon a 500 amp-hr per lb of metal yield would be 3.75 years. The resistors reduced the total current output to 3.935 amp or a current density of 1.25 ma. per sq ft. This reduction in current flow increased the expected installation life to 10.5 years.

The question as to what the actual tank-to-soil potential at the center of the tank would be with this type of installation was mentioned several times. It was decided to conduct a survey to determine this factor in Sept., 1946.

A long copper sulphate electrode made up in 5-ft sections was forced under the tank midway between two anode connections. Measurements were taken at 5-ft intervals from the periphery to the center of the tank and the results are shown in Fig 2 and Table 2. The results of this survey concur very well with Bond's statement that the drop in potential at the center of a 55,000-bbl tank is approximately 0.05 volt. The maximum drop in

TABLE 2—*Current and Potential Measurements on Welder Station Tank No. 29 before and after Installation of Magnesium Anodes*

Anode Station	Before Installation	After Installation					
		No Resistors (3/13/46)		With Resistors (4/20/46)		Pipe Lines Isolated 9/21/46	
	Tank-to-soil Potential, volts	Tank-to-soil Potential, volts	Anode Current Flow, amp	Tank-to-soil Potential, volts	Anode Current Flow, amp	Tank-to-soil Potential, volts	Anode Current Flow, amp
1	0.69	1.13 1.03	0.950	0.97 0.94	0.320	1.05 1.01	0.210
2	0.70	1.17 1.03	0.835	0.99 0.93	0.315	1.07 1.01	0.210
3	0.71	1.17 1.06	1.100	0.97 0.95	0.335	1.04 1.01	0.160
4	0.74	1.18 1.05	0.500	0.99 0.95	0.310	1.09 1.05	0.205
5	0.70	1.21 1.11	0.935	0.96 0.95	0.330	1.07 1.07	0.175
6	0.72	1.18 1.11	0.790	1.05 0.95	0.340	1.09 0.99	0.200
7	0.74	1.21 1.05	0.815	0.98 0.94	0.310	1.05 0.98	0.170
8	0.71	1.17 1.01	0.825	1.03 0.95	0.330	1.03 0.99	0.165
9	0.71	1.20 1.11	1.050	0.97 0.95	0.320	1.02 1.03	0.175
10	0.74	1.16 1.12	0.835	0.99 0.96	0.330	1.09 1.05	0.150
11	0.66	1.11 1.10	1.190	0.95 0.97	0.345	1.02 1.01	0.165
12	0.72	1.11 1.06	1.100	0.99 0.91	0.350	1.07 1.02	0.210
Total Current (Amp)			10.925		3.935		2.195

potential for the 20,000-bbl tank was 0.03 volt or one millivolt drop per foot from the periphery of the tank.

After these tests were conducted, all connecting pipelines were isolated from tank No. 29 by insulating the flanges at the valves.

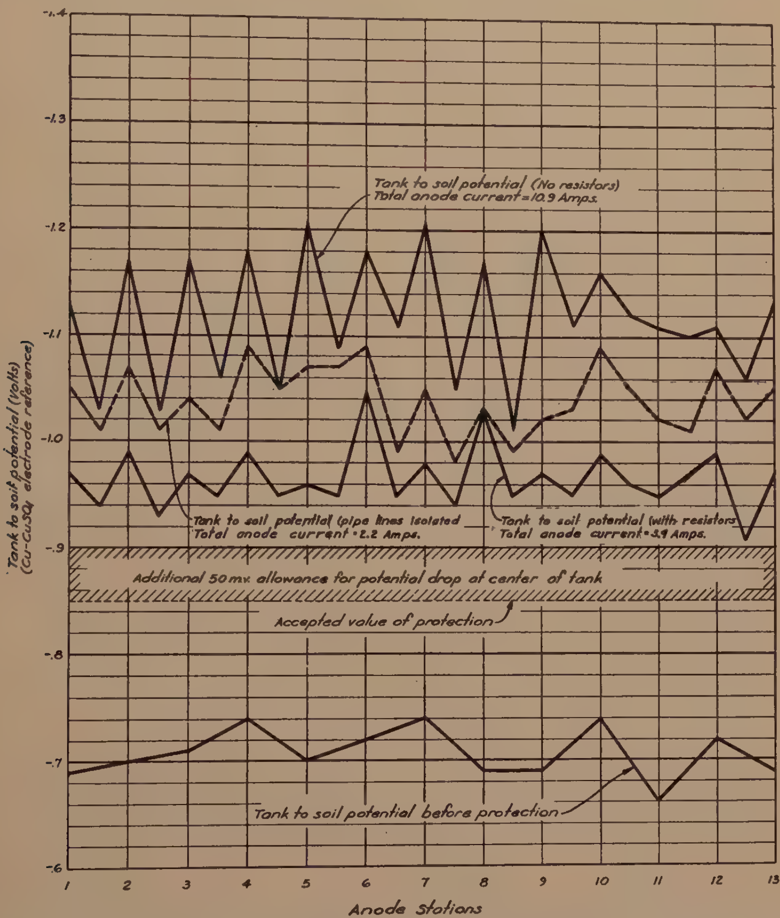

FIG 4—TANK-TO-SOIL POTENTIALS BEFORE AND AFTER INSTALLATION OF MAGNESIUM ANODES ON WELDER STATION TANK NO. 29. (DATA FROM TABLE 2)

Measurements taken after isolating the pipe lines indicated that a higher protective potential was realized with considerably less anode current. The potential values ranged from −0.98 to −1.09 volts with a total anode current output of 2.195 amp or a current density of 0.75 ma. per sq ft of tank surface. Isolation of the pipelines by reducing the anode current output has increased the magnesium installation life to 18 years.

The data taken on welder station tank No. 29 is tabulated in Table 1. Fig 4 is a graphical presentation of the tank-to-soil potential measurements under the three conditions just mentioned.

Thirty-two man-hours of labor were required to install the anodes and attach the lead wires to the angle-iron at the base of the tank. Four man-hours were needed to insert the 12 resistors in the lead wires.

At a later date, tank No. 29 was insulated from the connecting pipe lines; two men completed this work in 3 hours. The total material and labor cost on this complete installation was approximately $290 or a total annual cost of about $20 per year based on an expected installation life of 15 years. This estimated annual cost is sufficient to include the cost of a yearly survey if such is desired.

Conclusions

Cathodic protection employing magnesium anodes is becoming widely accepted as a solution to the corrosion problem on metal structures in contact with soil or water of which oil storage tank bottoms are an outstanding example. This method furnishes adequate tank-to-soil potentials at the center of the tank by installing anodes near the circumference. In addition to the low installation cost an important advantage lies in the fact that there is little or no maintenance cost as in the case of the electrolytic anode type of cathodic protection. The data presented here indicate that cathodic protection using magnesium anodes may be provided at an annual cost of 1 pct or less of the cost of replacing tank bottoms. This figure does not include the value of lost products from leaks or allow for losses resulting from equipment being out of service.

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Preventing Corrosion in Gas-condensate Wells

By P. L. Menaul* and P. P. Spafford†

(New York Meeting, March 1947)

Abstract

This paper discusses the most dangerous form of corrosion encountered in condensate-well oil production, the discovery of the agent causing this corrosion and the remedial chemical treatment proved effective by field use. The injection of ammonium hydroxide, even as little as one quart per day, has proved effective in preventing gas-condensate well corrosion. The injection of "Bone oil" is applied to wells producing brines containing calcium and magnesium salts.

Introduction

The severe corrosion of equipment in high pressure gas condensate wells has been a problem for several years and numerous papers have been presented on the subject.

The term "gas condensate" or "distillate well" is applied to a distinct variety of hydrocarbon producing well, the characteristics of these wells being high bottom-hole (formation) pressures and temperatures and high gas production. These wells usually produce about 40 gal of water per million cubic feet of gas and the gas contains from 0.1 pct to 2 pct carbon dioxide. In the operation of this type of well, the operators soon noted severe internal corrosion of the pipe carrying the production. In some instances the well tubing has been found to be corroded to perforation in eight months. The high well head pressures of 2500 to 8000 psi makes any weakening of the well equipment by corrosion extremely hazardous. Bursting of the well equipment results in very expensive repair operations and may result in the loss of valuable production, loss of the costly well, or even loss of life.

In November 1944, a gas-condensate well in a Gulf Coast field producing from 9500 ft showed a tubing leak. The well was "killed" by filling it with mud through the tubing, and then the tubing was pulled. Corrosion was found to have caused several perforations in the tubing, Fig 1. While the mud was being circulated to kill the well, a high pressure jet from the corroded hole in the tubing perforated the casing and damaged the well to the extent that the cost of repairs amounted to $75,000.

In November 1944, another gas-condensate well in a Gulf Coast field producing from 11,400 ft showed tubing failure. This well had been producing an average of 2,500,000 cu ft of gas daily for two years. In the workover of this well, it was found that a hole one inch in diameter had corroded through the tubing and that corrosion had reduced the wall of the tubing to less than half the standard thickness over large areas of the interior of the tubing. It was found that corrosion had also caused two leaks in the casing. After four months spent in an attempted workover failed to make the well safe for further production, the well was plugged and abandoned at a total loss of $300,000.00.

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Laboratory Investigation

In view of the great economic importance of condensate-well corrosion, an investigation as to the causative agent of this type of corrosion and the development of a method or methods of combatting this problem were undertaken at the Research Department Laboratory of the Stanolind Oil and Gas Company. The cause of condensate-well corrosion had remained undiscovered and it was not until organic acids of the acetic acid series were discovered to be the causative agent, that remedial measures could be developed. The results of these early investigations were reported.[1]

The laboratory investigation proved organic acids to be the primary factor contributing to condensate-well corrosion and with others[2] correlation was found between the organic acid content of condensate water and the observed corrosion in wells. Most condensate wells subject to organic-acid corrosion are situated within 100 miles of the Gulf Coast. It is of interest however that a relatively high content of organic acids, 432 pp, was found in a corrosive distillate type of well in the Waldon field, Colorado.

Fig 1—Corroded tubing from well condensate.

The corrosive agent being identified, laboratory research was undertaken to develop a remedial treatment. Test panels of mild steel of ½ by 4 in. in dimensions were suspended for seven days in five liter flasks of corrosive condensate waters treated with various proportions of different inhibitors. The flasks were maintained at a constant temperature of 180°F and extreme precautions were taken to exclude air from the water and other fluids used in the tests in order to simulate the oxygen-free subsurface well conditions as nearly as possible. Condensate water samples were collected under oil, also synthetic condensate waters used were degassed by boiling for two hours, and then were covered with oil. The vapor spaces in the five liter test flasks were filled with a mixture of oxygen-free nitrogen and carbon dioxide. Although no attempt was made to simulate the high pressures encountered in field conditions, subsequent field results have substantiated the data obtained in the laboratory.

[1] References are at the end of the paper.

The laboratory investigation showed that ammonium hydroxide[a] and "Bone oil"[a] were peculiarly effective in preventing corrosion of steel in condensate well waters.

Mechanics of Distillate Production

The liquid water recovered at the surface usually is in the vapor phase when it enters the well bore from the producing strata.

The volatile compounds of ammonia, i.e., ammonium hydroxide, ammonium carbonate, and others are particularly adaptable to the treatment of true condensate wells which produce virtually a distilled water, Table 1; the reason being that circulation of the inhibitor will be

Table 1—*Typical Analysis of Condensate Water*

Materials	Jennings Field, Louisiana	Katy Field, Texas
	PPM	PPM
Sodium Chloride	304	254
Sodium Bicarbonate	138	161
Calcium Sulphate	26	30
Calcium Chloride	19	7
Magnesium Chloride	20	21
Iron	220	255
Organic acids as acetic acid	480	450

insured even though the fluid being produced is in the vaporous state. The water produced from a true distillate well is a distilled water, in accordance with the mechanics of distillate production which conform with the laws of physical chemistry. In this we know that two or more coexisting liquid phases must possess a common vapor pressure and on distillation, both phases volatilize at the same temperature and in relation to their partial pressures in the vapor. We then find the volatile material of the producing strata represented in the condensate, though not necessarily in the same proportion as they exist in the formation, since some constituents may be concentrated.

[a] Patents pending.

The presence of organic acids in condensate water is accordant to the observed corrosion in condensate wells. Several thousand feet of the lower section of the tubing is usually unaffected by corrosion. The vaporous production is slightly undersaturated with water vapor because the brine in the formation from which it comes has a lower vapor pressure than pure water. As the vaporous production ascends the well, lower temperatures are encountered which causes the condensation of both water and organic acids which formed a corrosive solution. It is at this zone of condensation that the most severe corrosion is encountered. Downstream from this zone, the severity of corrosion decreases.

Field Use of Ammonium Hydroxide

Following the laboratory experiments, a field trial of ammonium hydroxide introduced in the annulus between tubing and casing was started. Commercial 26 pct solution was used to evaluate ammonium hydroxide as an inhibitor of condensate well corrosion. Small chemical injection pumps were found to be unsuitable for injection of chemical against the high well pressures so a gravity type chemical feeder was designed in the laboratory (see Fig 2) which was fabricated and installed on a corrosive gas condensate well. The chemical feeder was connected to the casing wing, chemical was introduced into the casing annulus and circulated up the tubing with the well production. The casing annulus must be free of packers or other obstruction to permit such treatment, also, any leak in the casing will allow the chemical to escape. The injection of chemical involves very little extra work and is handled by the switcher who takes care of the wells.

Upon initiating the chemical treatment, the chemical analysis for the iron content of the water showed a rapid decline of

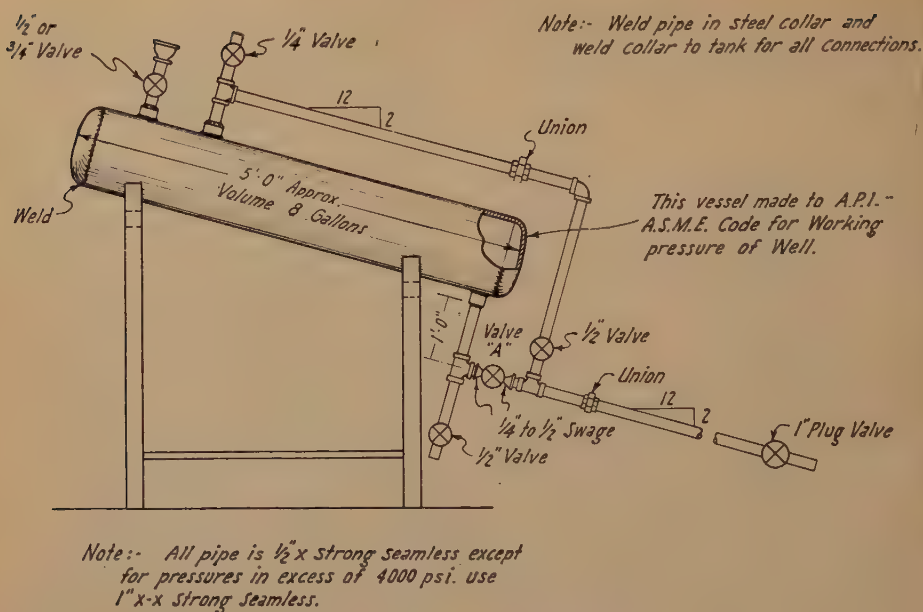

FIG 2—CHEMICAL FEEDER.

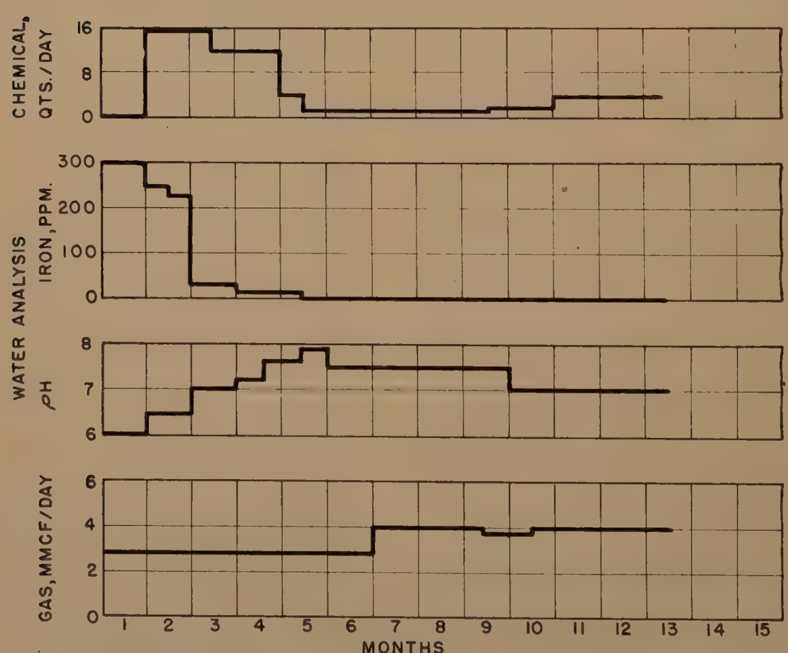

FIG 3—RESULTS OF AMMONIUM HYDROXIDE INJECTION ON WELL H.
Water production 1 bbl per million cubic feet gas.

corrosion; for continued data, the iron content of the water was determined at the wellhead or separator by the field engineer at frequent intervals who used a method[3] requiring only a few minutes.

It will be noted that the iron content of the produced water from the eight treated wells has been reduced to substantially zero which proves that corrosion is being effectively stopped. The

TABLE 2—*Data on Wells Where Chemical Is Injected*

Well	A	B	C	D	E	F	G	H	I
Ammonium hydroxide qt/day avg	4	4	4	3	3	3	4	2	12
Gas production, avg Mcf/day	1,000	1,000	1,000	10,000	10,000	1,500	2,000	3,000	4,870
Water production, avg bbl/day	1.0	1.6	1.0	4.5	4.0	0.5	1.4	3.5	8.13
Amount of CO_2 in gas				0.10[a]	0.54[a]			1.61[a]	0.60
Organic acids in water, ppm	338			480	420	150	360	630	404
Iron content of water ppm:									
Before treatment	280	210	280	210	156	150	380	250	287
After treatment	0	0	0	0	0	0	0	0	200
Ammonium hydroxide in effluent water qt/bbl	4	2.5	4	0.7	0.8	5	3	0.6	None

[a] Percent.

TABLE 3—*Typical Behavior of Gas Condensate Well Treated with Ammonium Hydroxide Well H, Table* 2

Period Treated, Days	Gas Production, Mcf	Bbl/H_2O per Day	Ammonium Hydroxide per Day	Water Analysis		
				Fe Ppm	pH	Organic Acids, Ppm
1	2,500	3	None	250	6.0	250
15	2,500	3	None	250	6.0	
30	2,500	3	4 gal	175	6.5	
45		3	4 gal	130	6.0	
60	2,540	3	4 gal	31	7.0	
70	2,540	3	4 gal	31	7.2	
90	2,540	3	3 gal	7	7.6	
105	2,540	3	3 gal	11	8.0	
120	2,158	3	1 gal	2.8	7.7	
135	2,340	3			8.0	
150	2,340	3	1 qt	2	7.5	
165		3	1 qt	0	7.4	
180	4,000	3	1 qt	0	7.5	
195	4,000	3	1 qt	0		
110	4,000	3	1 qt	0		
125	4,000	3	1 qt	0		
140	4,000	3	1 qt	0		
155	3,500	3	1 qt	0		
170	3,500	3	2 qt	0	7.0	
195	4,000	3	2 qt	0		
210	4,000	3	4 qt	0	7.0	
225	4,000	3	4 qt	0		
240	4,000	3	4 qt	0		
265	4,000	3	4 qt	0		

Such favorable results were obtained in the first field trial of ammonium hydroxide that additional wells were placed under treatment until at present, eight of the company's formerly corrosive gas condensate wells are being treated successfully with ammonia. The field results of the ammonia injection are summarized in Table 2.

quantity of ammonium hydroxide used daily to treat each well varies from one quart to one gallon.

Fig 3 shows the effect of continuous injection of ammonium hydroxide and continuous production of the well. A few days after the chemical treatment was begun, a decrease in the iron content of the effluent water was noted, then a

steady decline in the concentration of iron to less than ten parts per million shows the effectiveness of the treatment.

Fig 4 shows the effect of intermittent

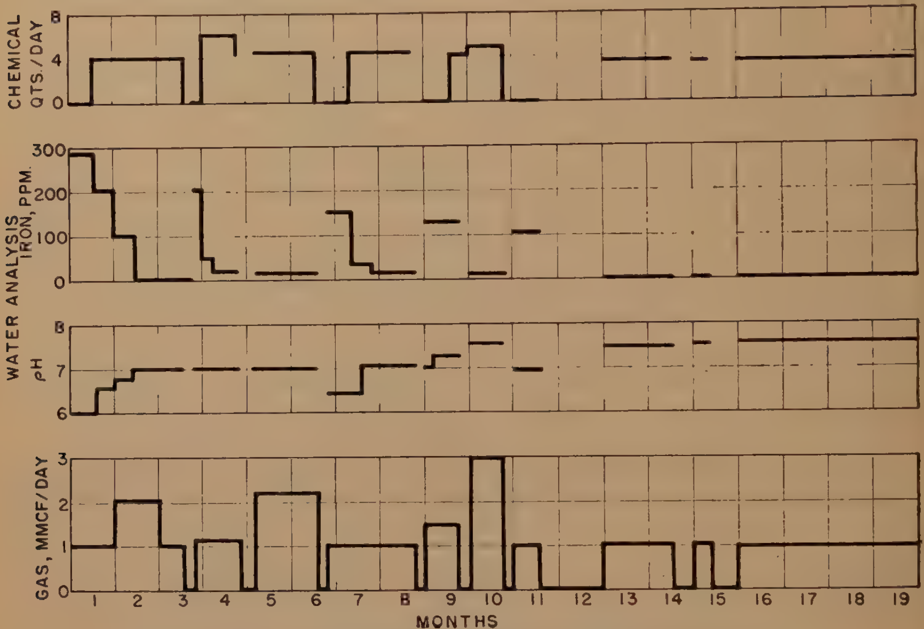

Fig 4—Results of ammonium hydroxide injection on well C. Water production 1 bbl per million cubic feet gas.

production of the well and inconstant ammonia injection. It may be noted that when ammonia injection was omitted for several short periods while the well was producing, the result was an increase in the iron content in the effluent water in the sixth, seventh, ninth and eleventh months. On resuming injection, the iron content declined showing that the corrosion control was directly dependent on chemical treatment.

Well I has not responded to chemical treatment (see Table 2). This well has been treated for five months with ammonium hydroxide but, as yet, no chemical has been detected in the effluent water. The reason for the failure of the chemical to circulate is not known.

Well H (see Table 3) is showing effective results from the injection of only one quart ammonium hydroxide per day, by a reduction of iron content from 250 ppm before treatment to 0 ppm after treatment. It is to be noted in particular that as this well is daily producing four MMcf of gas containing 1.6 pct carbon dioxide, the effectiveness of one quart of ammonium hydroxide used each day cannot be due to neutralizing the carbon dioxide, because it would require 1500 gal of ammonium hydroxide per day to convert all of the carbon dioxide in the gas to ammonium bicarbonate.

Effect of Ammonium Hydroxide Treated Production on Gasoline Plants

The effect of ammonia in the input fluid on the operation of gasoline plants has been questioned. Wells are being treated whose production goes directly to a gasoline plant. Chemical analysis of the products in the flow stream of the plant shows that the ammonia, which

has been added in by treating the wells is removed with the water discharged from the water knock-out separator. Almost all the water in the flow stream is removed at the separator which showed 600 ppm ammonium hydroxide which indicates that almost all the ammonia is removed at this point. Water samples taken at other locations in the plant showed only 13 to 60 ppm ammonium hydroxide. This low concentration of ammonia apparently does not affect the brass fittings or valves. Water from condensate wells usually contains 20 to 40 ppm unidentified compounds which react as ammonia in this test.[4]

Brine-condensate Wells

Some wells produce brine which enters the bottom of the well in liquid form carrying dissolved inorganic salts, principally sodium, calcium and magnesium chlorides in concentrations as high as 90,000 ppm. A typical analysis is given in Table 4. This brine is also acidic and,

Table 4—*Typical Analysis of Brine-condensate Water*

Material	Luby Field, Texas Ppm
Sodium Chloride	67,518
Sodium Bicarbonate	268
Calcium Sulphate	39
Calcium Chloride	17,894
Magnesium Chloride	1,057
Iron	60
Organic acids as acetic acid	120

due to the presence of liquid water throughout the flowstring corrosion is found distributed throughout the well system, and the severe localized corrosion may not be present. Although the corrosion in brine-distillate wells may not be as severe as that encountered in true gas-distillate wells, it is advantageous to treat these wells with chemicals also. The use of ammonium hydroxide in treating wells whose fluid carries calcium and magnesium will result in the deposition of scale that would plug the flow lines. For treating brine-distillate wells, the laboratory experiments previously mentioned indicate that "Bone oil" is a promising inhibitor.

Discussion of Results

The value of chemical investigations in discovering the cause of and the remedial measures for gas-condensate well corrosion is apparent. Field operations will include the following steps:

1. Wells subject to corrosion may be detected by chemical analysis of the water, performed at the wellhead.

2. If preliminary tests of iron in the effluent water indicate severe corrosion and it is decided to treat the well then a laboratory analysis of the effluent water is made. If the chemical analysis shows a low content of total dissolved solids and especially low concentrations of calcium and magnesium salts, then ammonium hydroxide is recommended as the proper chemical to be used for treating the well.

3. On starting chemical treatment at a well, the water is sampled daily and tested for the presence and concentration of the chemical injected to make sure that the chemical is circulating properly. Some unknown condition of the well such as a packer or other obstruction in the annulus, will prevent the circulation of chemical. A casing leak would wash the relatively small amount of chemical out of the well.

4. During chemical treatment of the well, samples of the effluent water are analyzed at regular intervals to determine the optimum rate of chemical injection and to note if the chemical characteristics of the water production change and require a change of treating chemical.

Conclusions

The causative agent of corrosion in high pressure gas-condensate wells has been discovered. Ammonium hydroxide

and "Bone oil" were found by laboratory experiments to be peculiarly effective in preventing this type of corrosion.

Daily injection of a small quantity of ammonium hydroxide into the casing annulus has proven effective in entirely preventing this type of corrosion.

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Acknowledgment

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Meter for Measuring Distribution of Gas Flow in Well Bores

By F. Morgan,* D. W. Reed,* and L. L. Gray,† Member AIME

(New York Meeting, March 1947)

Abstract

A flowmeter has been developed at Gulf Research and Development Co. and tested in the field for measuring the flow of gas in well bores. It has been used in a study of the injection capacity of different horizons in gas injection wells in Oklahoma.

The flow sensitive element of the meter is a semi-conductor having a very high temperature coefficient of resistance. Advantages possessed by this meter are the result of that property and the high specific resistance of the element. The instrument possesses a sensitivity considerably higher than any reported previously.

In the application described here the element is heated to a temperature considerably above ambient by an electric current, which is supplied by a voltage source at the surface. When fluid flows through the meter the rate of dissipation of heat is increased and the temperature of the element decreases. Because of the negative temperature characteristics of the resistance element such a decrease of temperature will be accompanied by an increase of resistance which, under flow conditions ordinarily found in wells, is of such a magnitude that it can be directly measured or recorded in terms of a change in voltage at the surface.

In practice, rate of flow is measured in terms of the drop in voltage in the resistance element. All the metering and control apparatus remains at the surface while the thermal element is lowered into the well on a single conductor cable, consisting of an insulated wire and sheath. The meter is calibrated by passing known quantities of gas through it either at the surface or in the hole at a point immediately above the region in which gas is lost to the formation. In case calibration is made at the surface, the ambient temperature in the hole may readily be obtained by a second resistance element which is operated at a current so low that effectively no heating occurs.

The instrument has been adapted to continuous recording, but the velocity of the meter relative to that of the gas must be low unless corrections are made. Curves giving data obtained in actual field tests are shown. The meter can also be used to determine the distribution of flow capacity in a gas producing well.

A differential form of the meter has been designed and built in which the local flow or injection capacity of the formation is obtained directly.

Introduction

When fluid is injected into a well in a secondary recovery or pressure-maintenance operation the question of its most effective use invariably arises. Although the core log, when available, will show the regions of good permeability and oil saturation, there is normally no assurance that the fluid actually enters the formation in zones where injection is deemed desirable. In view of the uncertainties involved in such programs, it is generally conceded that measurements of permeability for a formation in place are more significant than those obtained by the core-sampling technique.

A subsurface meter has been developed at the Gulf Research and Development Co. for measuring flow of fluids at different horizons in a well bore, and field tests have been made on the instrument in cooperation with the Tulsa Division of the Gulf Oil Corp. In this paper the meter is de-

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scribed and the results obtained by its use in gas injection wells are reported. It will be apparent that the instrument will serve equally well for the measurement of flow in producing wells.

Description of the Meter

Fig 1 shows an assembly drawing of the meter. It is approximately 4½ ft long, and the body diameter is 3½ in. In the field tests the instrument was lowered into the well on an insulated cable used in well-surveying operations, and all the measurements were made at the surface of the ground. For the purpose of these tests the meter was packed off in the sand by the use of a sponge rubber packer. This packer was slightly larger in diameter than the open hole. The wells that were logged by the meter have low injection rates, and by the use of the packer the high flow sensitivity was utilized.

The meter will detect fluid flows of approximately 0.5 ft per minute linear velocity, and is capable of accurately measuring flow rates of the order of 5 ft per minute. This high sensitivity is obtained by the use of measuring elements known as thermistors.[1] These are non-linear semiconductors, consisting of such materials as uranium oxide, zinc oxide and so forth which have high negative temperature coefficients of resistance. As the initial resistance is high, voltages to be measured fall within the range of the ordinary high resistance voltmeter and recorder. An additional advantage is that the power requirements are very low. The high temperature coefficient is especially valuable, as it is that property that leads to high sensitivity and large voltage changes.

At very low values of current Ohm's law is generally obeyed by thermistors. As the current is increased the voltage drop across the thermistor reaches a maximum and then decreases. In this region the thermistor

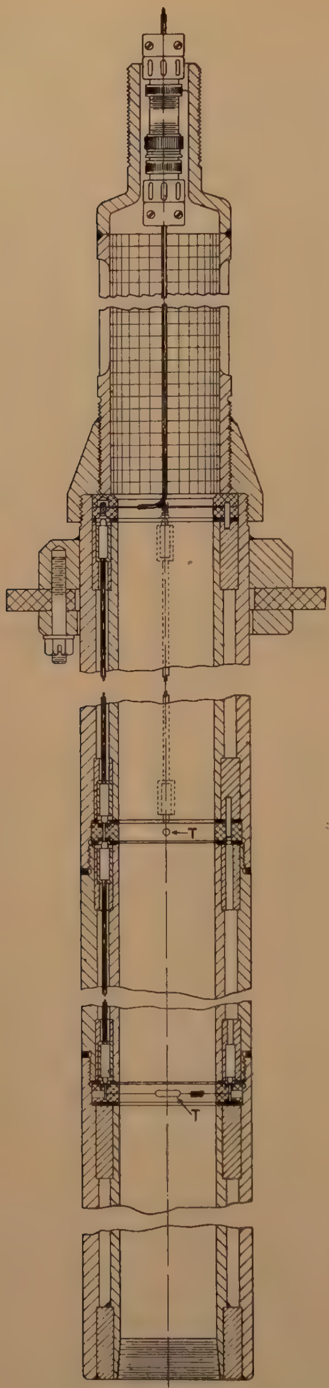

Fig 1—Assembly drawing of flowmeter.

[1] J. A. Becker, C. B. Green and G. L. Pearson: *Elec. Eng.* (1946) **65**, 711.

acts as a negative resistance; i.e., as the current increases, the voltage drop across the element decreases. At still higher values of current the slope of the current-voltage

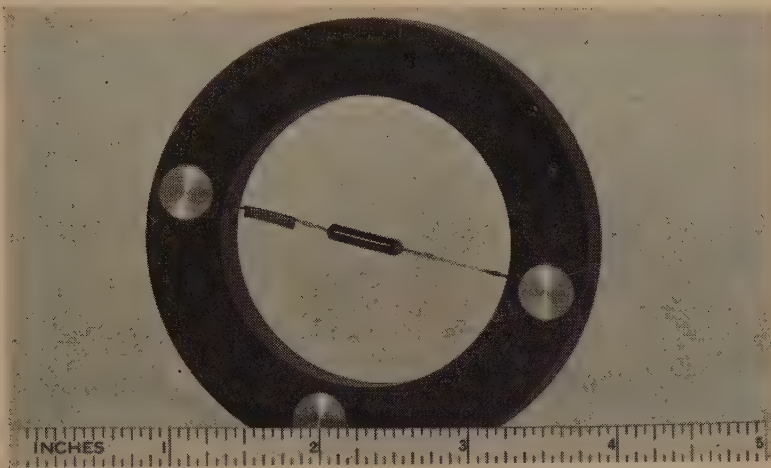

FIG 2—THERMISTOR AND MOUNTING.

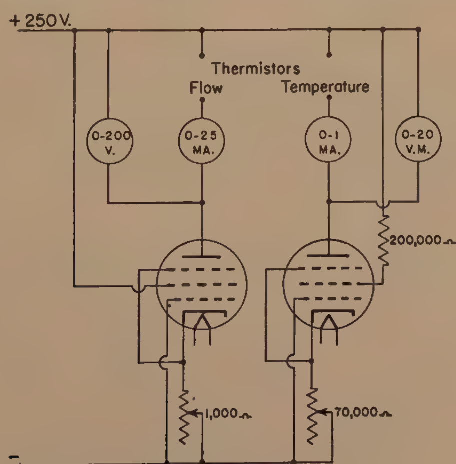

FIG 3—CURRENT CONTROLLER CIRCUIT.

curve again becomes positive. In order to avoid the complications and ambiguities that would normally arise if an element possessing such a characteristic curve were operated at a constant voltage, the thermistor was supplied a current which was held essentially constant by a self-biased pentode.

For experimental purposes the meter contained two thermistor elements, indicated by T in Fig 1. The top thermistor was used to measure ambient temperature and the bottom thermistor was the flow-measuring element. Either of these can be used independently.

Fig 2 shows a photograph of the mounted thermistor. The element is approximately ⅛ in. in diameter and ½ in. long.

Essentially constant currents are supplied the thermistors from the source

located at the surface of the ground. Fig 3 shows the circuit. The temperature-measuring element has a very small current passed through it, so that there is practically no the element is produced, and the resistance and voltage drop increase.

A photograph of the meter and the auxiliary equipment is shown in Fig 4.

FIG 4—FLOWMETER AND AUXILIARY APPARATUS.

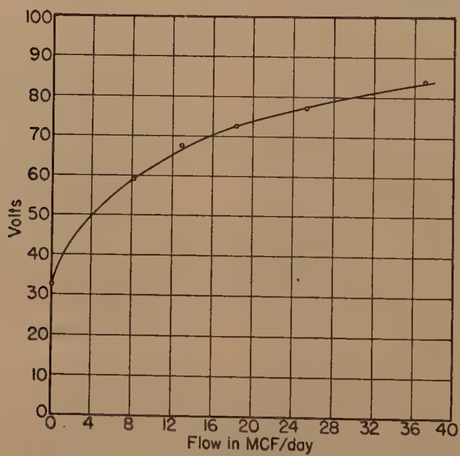

FIG 5—TYPICAL CALIBRATION CURVE FOR FLOWMETER.

heating of the element. Consequently, any change of resistance and voltage in this circuit is a function of the ambient temperature change. A much higher controlled current is passed through the flow thermistor. This current raises the temperature of the element considerably above ambient. When fluid flows in the meter a cooling of

FIELD PROCEDURE AND RESULTS

An orifice meter was installed at the well for measuring the gas input and for calibration purposes. The instrument was run into the well through a stuffing box and lubricator. A gate valve above the incoming gas line made it possible to insert or remove

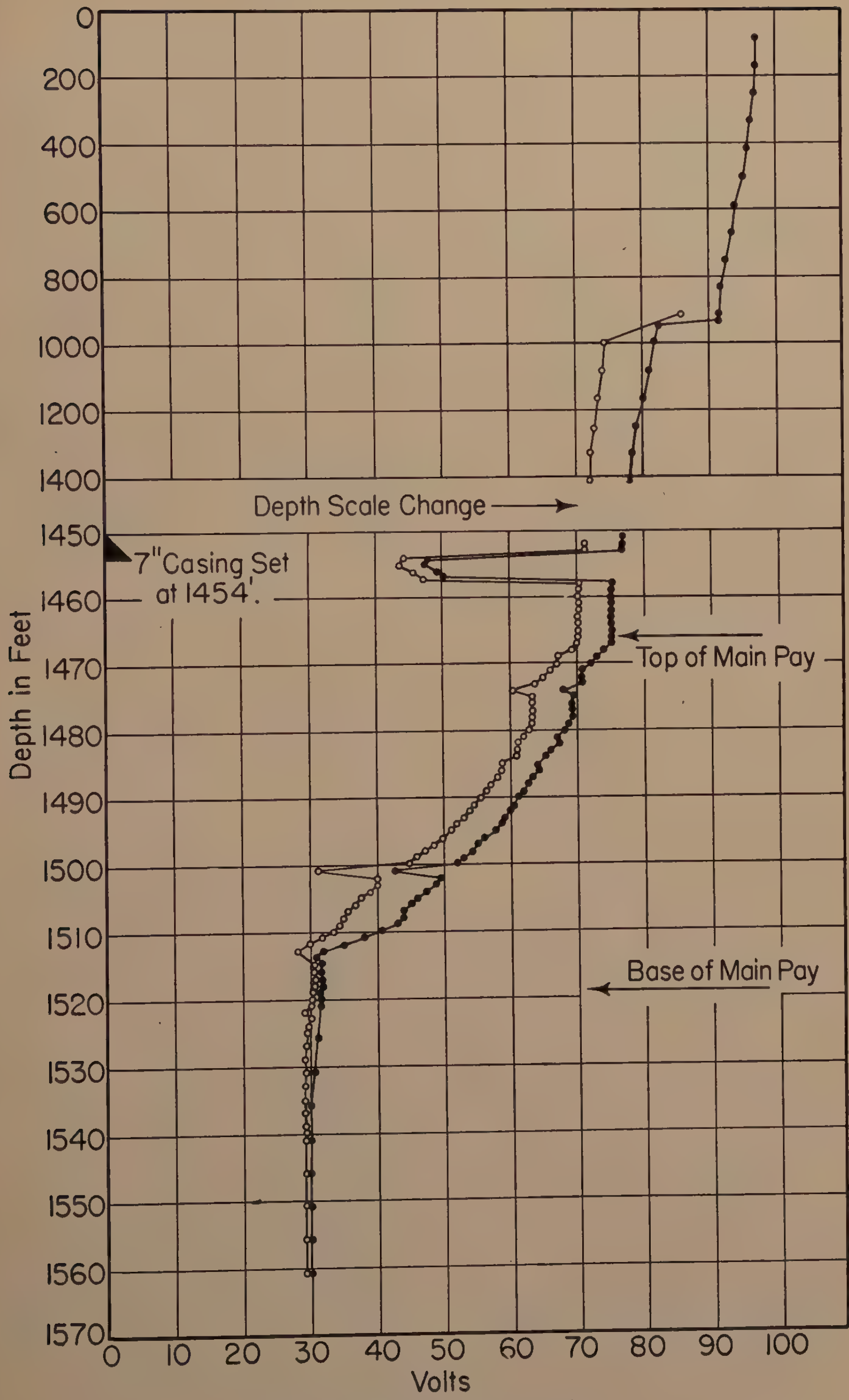

FIG 6—VOLTAGE LOG FOR WELL NO. 1.
○: Injection rate 30.7 Mcf per day.
●: Injection rate 34.8 Mcf per day.

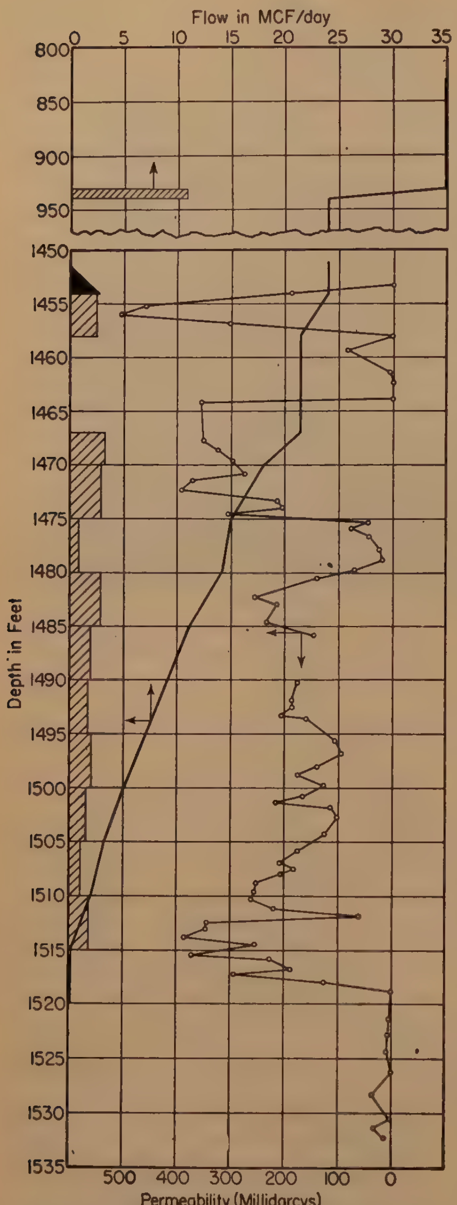

FIG 7—FLOW IN WELL BORE, LOSS TO FORMATION AND CORE-PERMEABILITY LOG FOR WELL NO. 1.

Solid line: Loss in well bore.
O: Permeability log.
Cross hatching: Loss to formation.

the meter without stopping the flow of gas to the well.

For calibration purposes the meter was lowered to a point approximately 5 ft above the casing seat and the input to the well was varied. At each calibration point the flow rate was maintained essentially constant until equilibrium was attained. Fig 5 is a typical calibration curve of the flow thermistor.

Fig 6 shows two voltage logs of the open hole and one of the casing for well No. 1. Conversion is made to flow against depth by the use of the calibration curve. At the time these data and the data for Fig 6 were taken the measuring meter and syncronized recording voltmeter were not available. Consequently, these curves are for flow in the well at the particular depth intervals shown on the graphs. The voltage across the element was measured by the external voltmeter, and depth measurements were made by stringing the cable into the well.

Although the two sets of plotted data were obtained for two different flow rates, 30.7 Mcf per day and 34.8 Mcf per day, as well as for two different diameter rubber packers, they nevertheless show practically the same characteristics. The second run was made partly as a test of reproducibility of the instrument and partly because the first flow rate was discovered to be less than the normal injection rate after the test was completed. The abrupt drop in voltage at a depth of 931 ft was observed on every trip past that point. Since the second thermistor indicated little or no temperature variation in that immediate vicinity, the most obvious explanation is that there was a leak in the casing. A sharp break in the curve at the casing point was observed on both runs. Since this drop did not persist at greater depths, however, it is evident that the meter had entered an enlarged hole for the extent of a few feet; i.e. from 1454 to 1457 ft. Actually the well log shows that the hole had been reamed

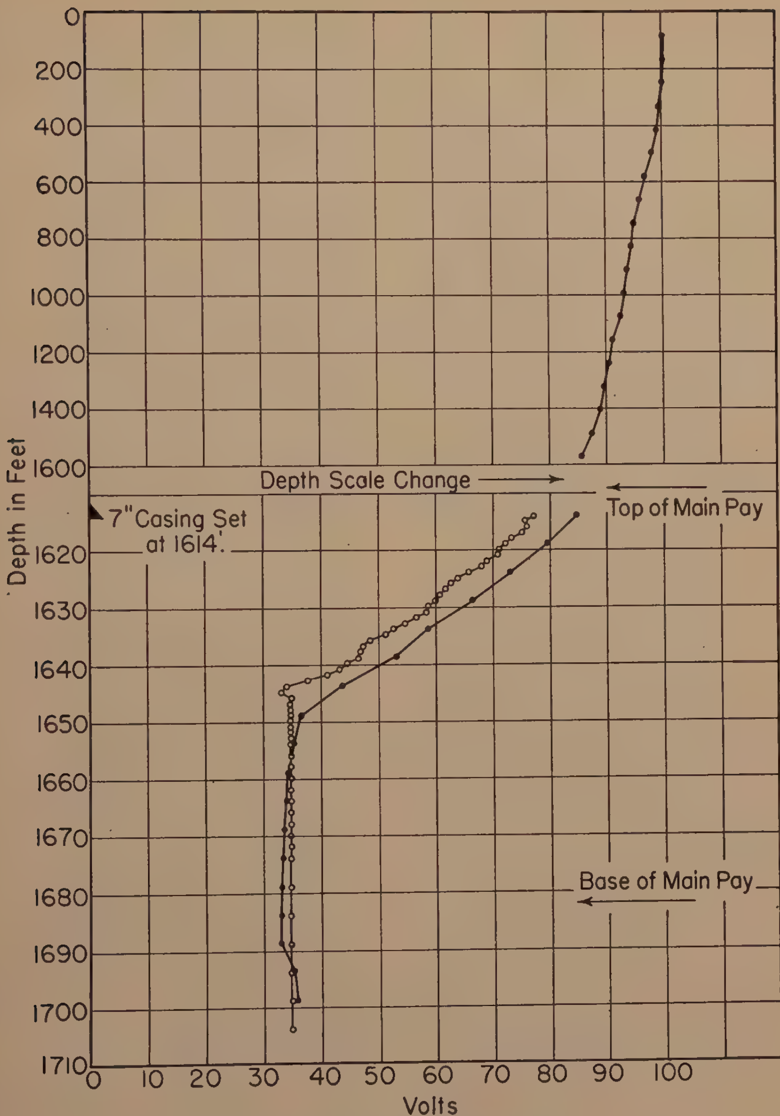

FIG 8—VOLTAGE LOG FOR WELL NO. 2.
○: Injection rate 24.7 Mcf per day.
●: Injection rate 37.0 Mcf per day.

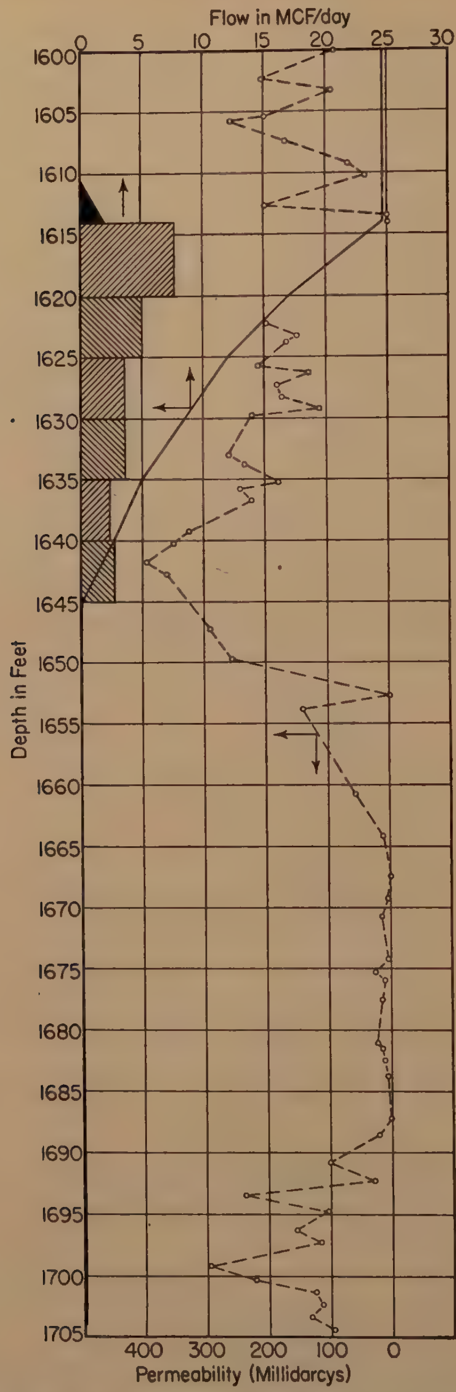

FIG 9—FLOW IN WELL BORE, LOSS TO FORMATION AND CORE-PERMEABILITY LOG FOR WELL No. 2.
Solid line: Loss in well bore. Broken line: Core permeability log.
Cross hatching: Loss to formation.

out to a depth of 1457 ft before the casing was set at 1454 ft. The large and sudden breaks in the voltage curves, such as occur at 1474 and 1501 ft are caused by leakage of gas past the meter at enlarged sections of the hole.

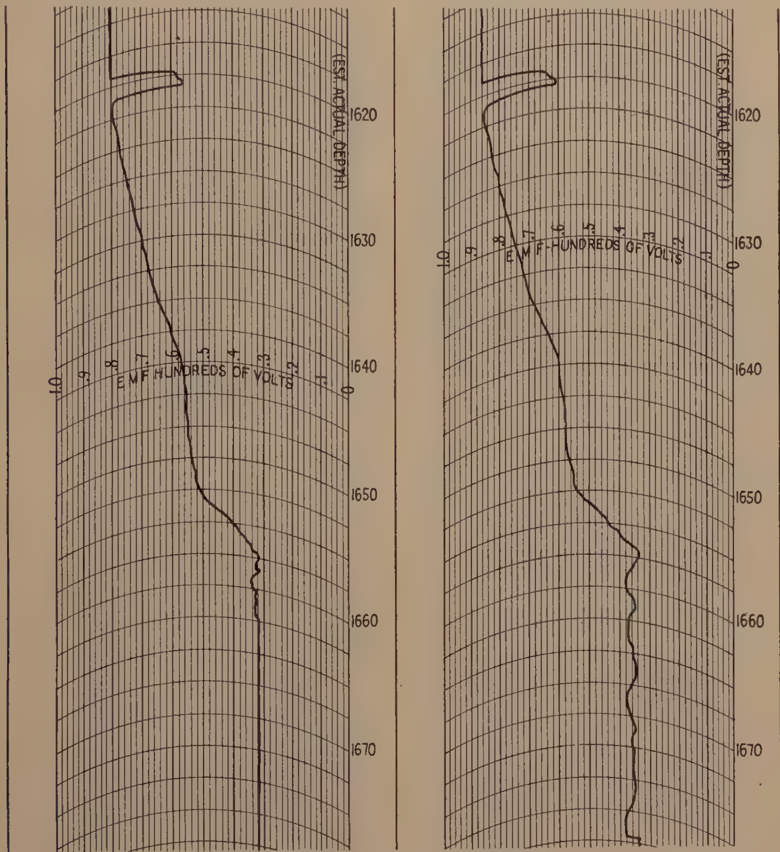

FIG 10—VOLTAGE LOG FOR WELL No. 3.
Left: Injection rate 39.7 Mcf per day.
Right: Injection rate 55.3 Mcf per day.

Fig 7 shows the flow in the well bore and the loss to the formation in Mcf per day, along with the core-permeability log for this particular well. The flow data plotted here were obtained from Fig 6.

Fig 8 is a voltage log for well No. 2. The first data were taken at a flow greater than the normal input to the well and at 5 ft intervals. This was more of an exploratory run to ascertain whether any abnormalities existed in the well. Since nothing unusual showed up in the first set of data, the flow in the well was reduced to normal input and the second log was taken at one foot intervals. The injection rates for these two curves were 37.0 and 24.7 Mcf per day.

The data for Fig 9 were derived from Fig 8, and again show the flow in the well bore, loss to the formation in Mcf per day and the core permeability log for this particular well. The results of the test show that practically all of the injected gas entered the formation between 1614 and 1645 ft, even though the core-permeability graph shows a permeable section between 1693

and 1700 ft. Failure of the gas to enter the lower sand may, however, have been due to low effective gas permeability as a result of water invasion. In cleaning out the well, prior to running the meter, water was used to remove a salt bridge. Excess liquid was then bailed out, but it is questionable if sufficient time had elapsed for the sand to return to its original condition before the well was logged.

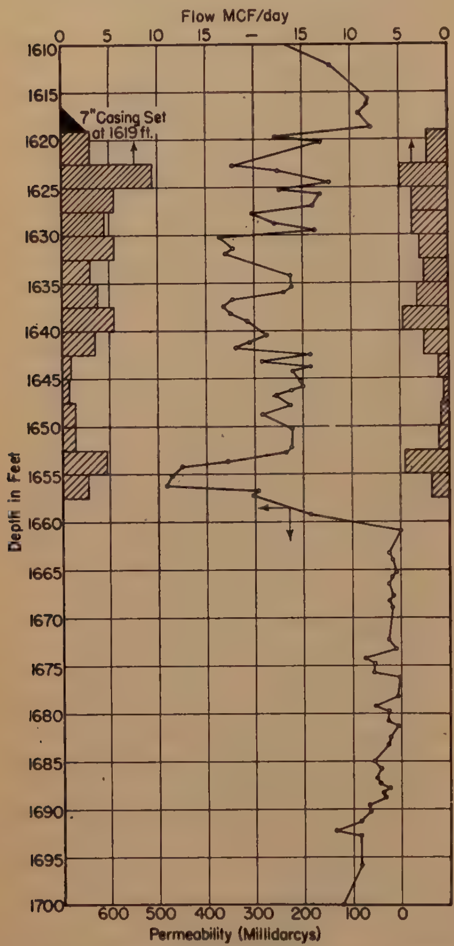

FIG 11—LOSS TO FORMATION AND CORE-PERMEABILITY LOG FOR WELL NO. 3.
O: Permeability log.
Cross hatching: Loss to formation.
Left: 55.3 Mcf per day.
Right: 39.7 Mcf per day.

The voltage vs depth curves of Fig 10 are for well No. 3. These curves are for injection rates of 39.7 and 55.3 Mcf per day.

Unlike the curves shown for the previous wells, these curves were obtained by the continuous recording of depth vs voltage across the flow thermistor. For recording purposes the meter was lowered in the uncased hole at a linear velocity of approximately 1 ft per minute. This varied considerably over short time intervals because gearing was not available on the cable drive. The rate of fall could only be controlled manually by the use of a hand brake.

Fig 11 shows the loss to the formation in Mcf per day over 2½ intervals of the formation, derived from Fig 10, as well as the core permeability log for well No. 3. Although the total depth of the well is 1718 ft, it will be seen from the curves that the injected gas entered the most permeable part of the formation in the section from 1619 to 1657 ft.

In Fig 12 the records for well No. 4 are reproduced. The curves were obtained in the same manner as for well No. 3. The sudden voltage drop at 1499 ft was observed both times the formation was logged, and is caused by gas by-passing the meter at an enlarged section of the hole. Injection rates were 35.5 and 62.2 Mcf per day.

The amount of injected gas in Mcf per day for the two different flow rates over 2½-ft intervals of the formation and the core-permeability log for the well are shown in Fig 13. The total depth is 1595 ft, but essentially no gas entered the formation below 1542 ft.

The recorded depth-voltage curves for well No. 5 are shown in Fig 14. These curves are for injection rates of 15.9 and 25.1 Mcf per day. The dropping speed and method of control were the same as for wells No. 3 and 4.

Fig 15 shows the distribution of injected gas entering the formation and the core-permeability log for well No. 5. In this

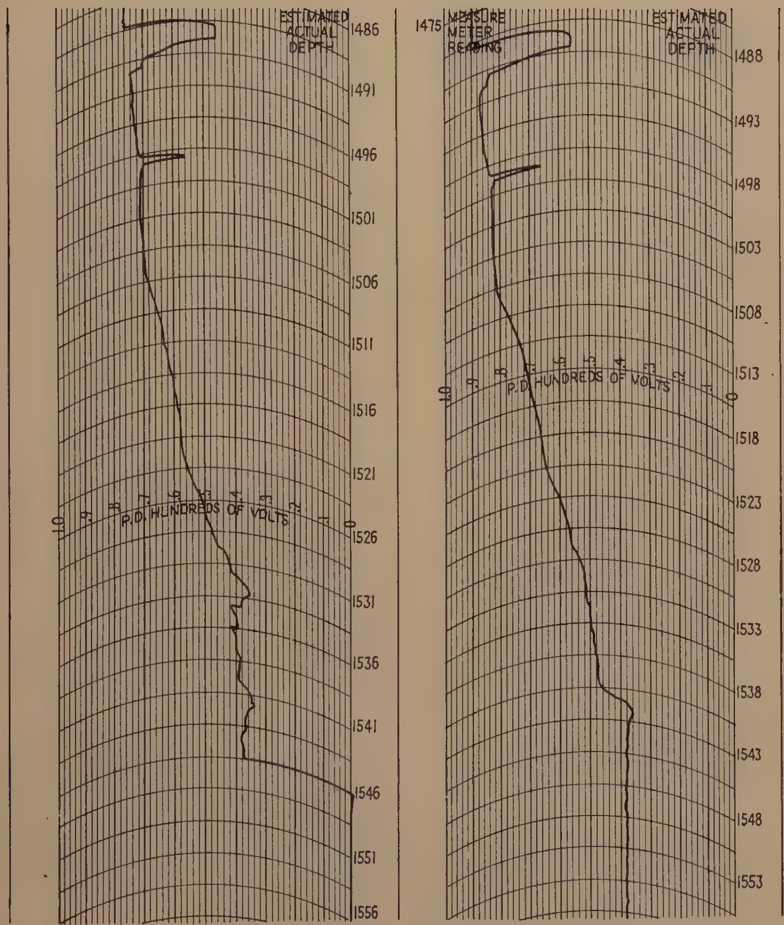

FIG 12—VOLTAGE LOG FOR WELL NO. 4.
Left: Injection rate 35.5 Mcf per day.
Right: Injection rate 62.2 Mcf per day.

case repressuring was extended to a slightly greater depth by increasing the injection rate.

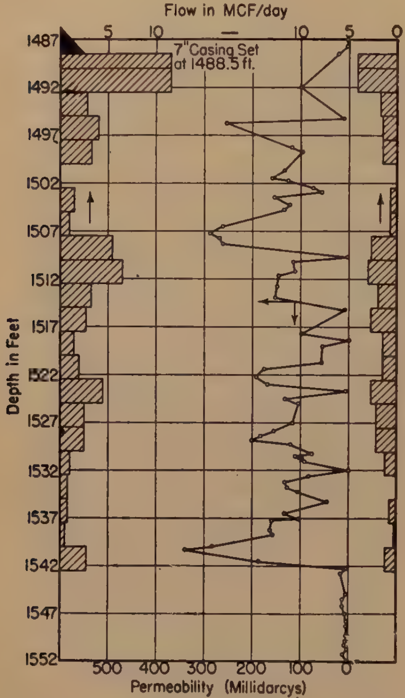

Fig 13—Loss to formation and core-permeability log for well No. 4.
O: Permeability log.
Cross hatching: Loss to formation.
Left: 62.2 Mcf per day.
Right: 35.5 Mcf per day.

Differential Meter

A differential type of meter has been designed and built in which the local flow or injection capacity of the formation is obtained directly. A photograph of the instrument is shown in Fig 16. In construction it is essentially the same as the meter of Fig 1, with the exception that a means of gas escape is provided through slots between two flow thermistors. A second packer is added to direct the flow of gas through the meter.

When using the differential meter both thermistors are used to measure flow, as shown in the circuit of Fig 17. The elements are selected to have nearly identical characteristics. Equal currents are passed through both elements and both are heated to a temperature much higher than ambient. The measured voltage in this case is the difference in voltage drop across both thermistors.

For calibration purposes in the casing, or when all of the injected gas is flowing past both elements, one thermistor is disconnected from the circuit and a voltage reading taken across the remaining element. Since both elements have the same characteristics, calibration of one is sufficient.

Discussion of Results

Comparison of the gas flow into the formation with the permeabilities as determined from core analyses shows that while point to point agreement does not exist, there is a general correlation between the permeability and flow-meter logs. Of course, exact equivalence should not be anticipated, as a number of extraneous factors are involved. For example, the effective permeability to gas will undoubtedly depend upon the liquid saturation of the sand, while the permeabilities shown on the core log were all measured on dry cores with air. However, in spite of the lack of detailed correspondence, there are certain broad general features that should be recognized. In the first place, in every case, essentially all of the gas entered the highly permeable sand between the casing seat and the shale break, at the base of the main pay, while little or no gas was injected into the lower sand. In well No. 1 the casing was apparently set above a very permeable section which, in turn, is distinct from the main producing sand. Figs 6 and 7 show that considerable gas was injected into this upper sand while no loss was detected in the shaly bed between 1458 and

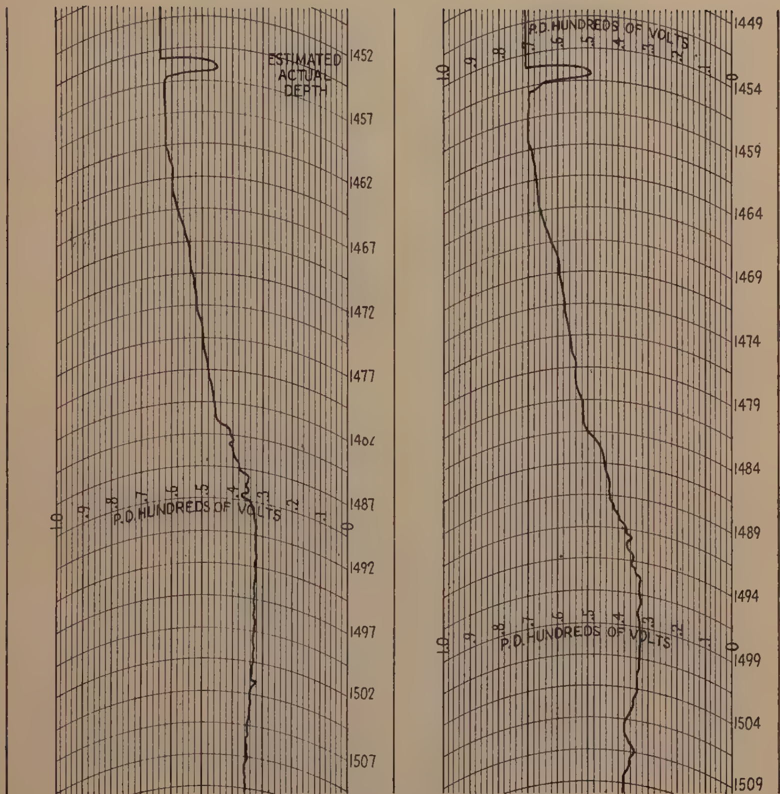

Fig 14—Voltage log for well No. 5.
Left: Injection rate 15.9 Mcf per day.
Right: Injection rate 25.1 Mcf per day.

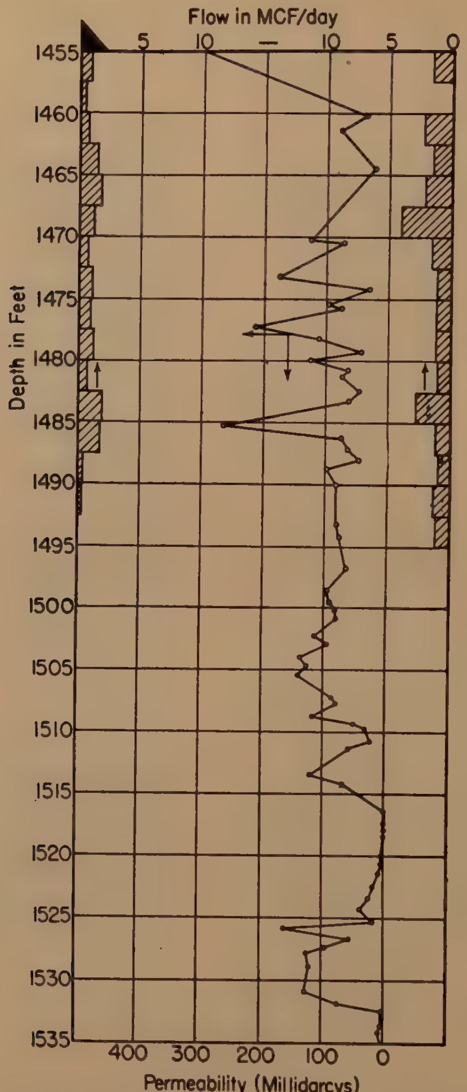

FIG 15—LOSS TO FORMATION AND CORE LOG FOR WELL No. 5.
O: Permeability log.
Cross hatching: Loss to formation.
Left: 15.9 Mcf per day.
Right: 25.1 Mcf per day.

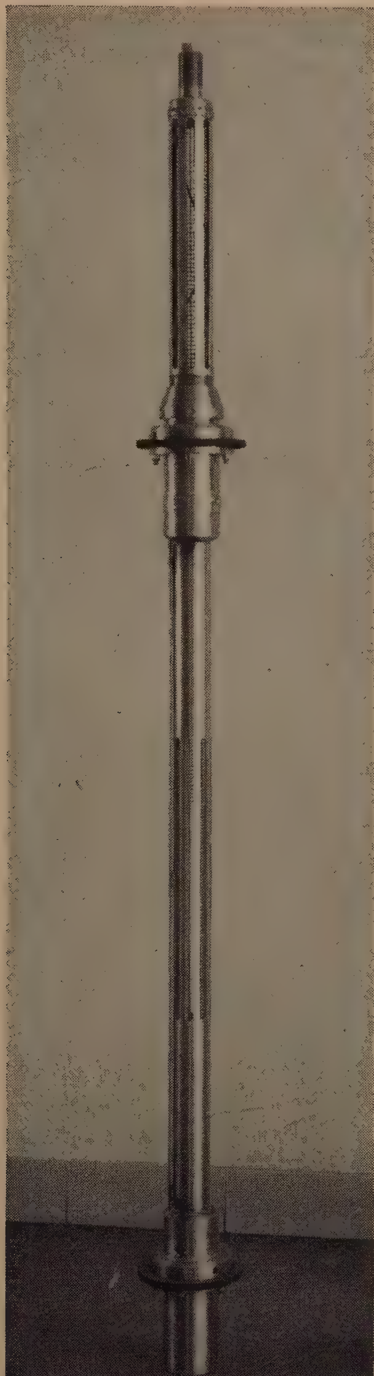

FIG 16—DIFFERENTIAL TYPE OF FLOWMETER.

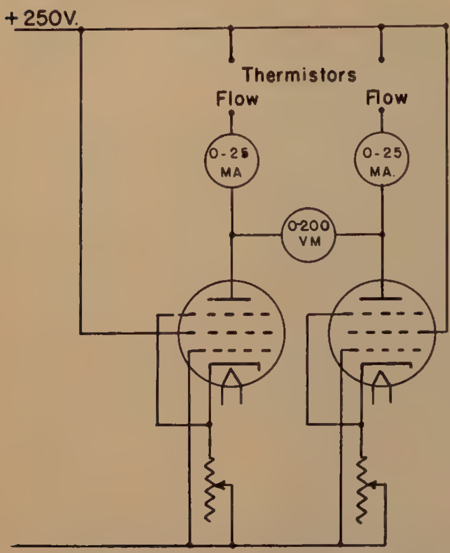

FIG 17—CURRENT CONTROLLER CIRCUIT FOR DIFFERENTIAL METER.

1467 ft. The fact that no gas was injected in the section from 1464 to 1467 ft although the permeability apparently is high, is not surprising as the driller's log indicated that the second sand actually begins at 1467 ft.

ACKNOWLEDGMENTS

The authors wish to acknowledge the collaboration of Dr. M. Muskat in the development of the meter and the interpretation of the results. Appreciation is also expressed to the management of the Gulf Research and Development Co. and the Tulsa Division of the Gulf Oil Corp. and to the Engineering Departments at Tulsa and Glenn Pool for extremely valuable direction and assistance.

An Improved Water-input Profile Instrument

By R. J. Pfister*

(Tulsa Meeting, October 1947)

Abstract

The development of a water-input profile instrument based on the introduction of brine and fresh water into an input well with the electrical location of the boundary developed between them is reported. Two methods are available in the use of this instrument to measure the foot by foot water-intake rates of the various sand strata: the moving boundary method in which variable well bore diameters can be determined and/or cancelled out and the constant boundary method. The type of results obtained and the relative advantages of each of these methods are described in detail.

Representative data are included covering the use of this instrument in experiments involving selective acidizing, selective plugging, and selective shooting. In such experiments, this instrument has been used to diagnose the unfavorable distribution of water intake in input wells and also to determine the effectiveness of the resultant treatments. The data included also serve to illustrate the type of problems which can be studied with this technique.

Introduction

For ten years or perhaps longer a number of progressive water-flood operators have felt the need for some method to measure the foot by foot water-intake rates of various strata in water-injection wells. The primary need is to diagnose unfavorable water distribution in various strata and to evaluate the effectiveness of the corrective measures such as selective acidizing, selective plugging, and selective shooting. Previously described methods for obtaining this type of data were not considered entirely adequate.[1,2] The profile equipment described in this paper embodies the separate introduction of brine and fresh water into the well at carefully measured and controlled rates and the electrical location of a sharp boundary developed between these fluids.

At present this instrument is a research tool of value in determining the effect of various well treatments on an individual sand strata. Its primary use has been on wells in which different sections require different treatments (e.g., wells with an open sand to be plugged and a tight sand to be acidized). It has, thus, made possible the determination of a rearrangement of the water intake of a well. The instrument can also be used to direct the treating material into a given zone. In completing a well the less permeable sands are shot more heavily with nitroglycerine in order to equalize the water intake between the permeable and less permeable sands. The extent to which such corrective shooting has been successful can be determined by a water-input profile. The combined profile and well-bore diameters should also provide a method for determining the direction and effect of various selective shooting techniques.

Equipment

The essentials of the water-input profile technique for measuring the intake per foot of individual sand strata are the injection of a nonconducting fluid, water, at the top of the well and a conducting fluid, brine, through a separate string of

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1 References are at the end of the paper.

small tubing to the bottom of the well in such a manner as to maintain a sharp boundary which can be located electrically

FIG 1—CONTROL TRAILER AND HIGH-PRESSURE BRINE TANK.

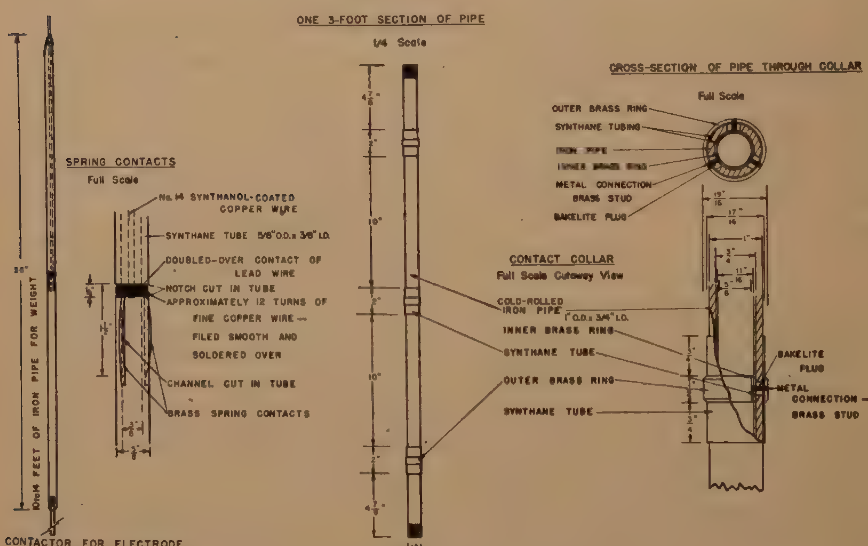

FIG 2—WATER-INPUT PROFILE PROBE.

foot by foot opposite the formation under study. The equipment affords delicate controls and means of measuring and recording both the brine and water injection rates.

The equipment consists of three units: a control trailer and a high-pressure tank trailer for mixing and injecting brine shown in Fig 1; and a probe element which can be lowered to the formation under study on a ¾ in. string of well tubing shown in Fig 2. Pressured lease water commonly available

at any injection well is required as a source of fresh water and as a pressure source for brine injection.

The control trailer contains first, a piping arrangement for injecting and measuring the water and brine flow rates using orifices and high-pressure manometers shown in Fig 3; and, second, an electrical pickup device by which the brine boundary can be located and its conductivity measured on a recording milliammeter. Fig 4 illustrates the flowsheet for the brine and water injection. The orifices are so arranged as to permit interchanging the orifice plates without disturbing the total equilibrium injection rate using alternately

FIG 3—HIGH-PRESSURE ORIFICES AND MANOMETERS IN TRAILER.

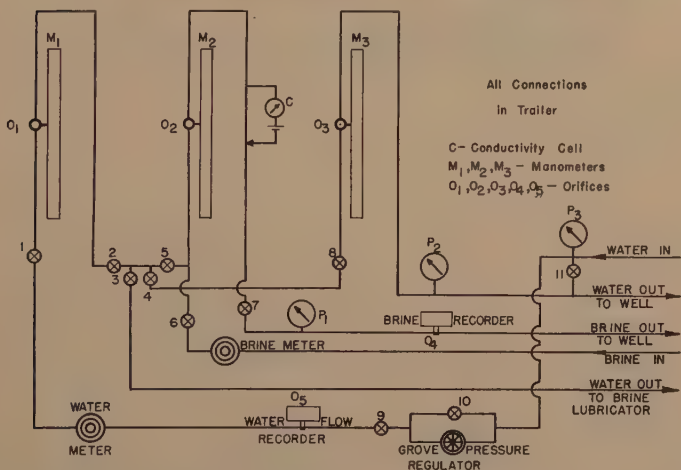

FIG 4—FLOWSHEET FOR MEASUREMENT AND CONTROL OF WATER AND BRINE FOR INPUT PROFILES.

water or brine. Since the lease water supply is subject to up and down pressure fluctuations it enters the control trailer through a Grove-gas loaded-precise pressure regulator shown in Fig 5. The regulator is shown immersed in a tank of water to minimize temperature fluctuations. Working pressures are slightly below the lease

pressure. The volume of high-pressure water is continuously recorded on an orifice flowmeter, shown in Fig 5, and also may be read on a displacement water meter. For which picks up the brine at the bottom of the tank, filters it and discharges it into the top of the tank. During brine injection, the valves are closed to the low-

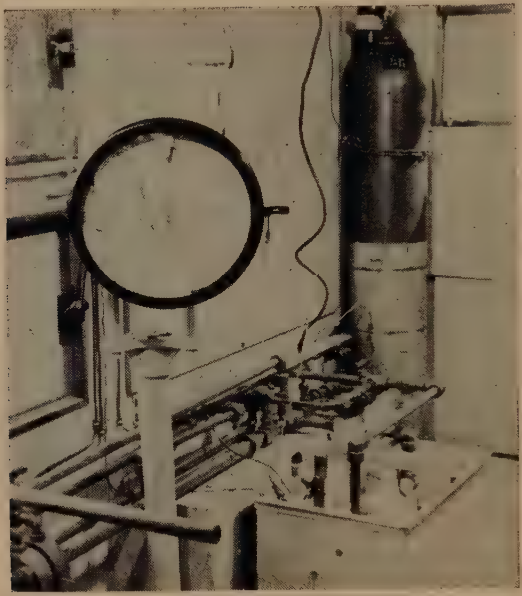

Fig 5—Recording pressure and flowmeter and Grove pressure regulator in trailer.

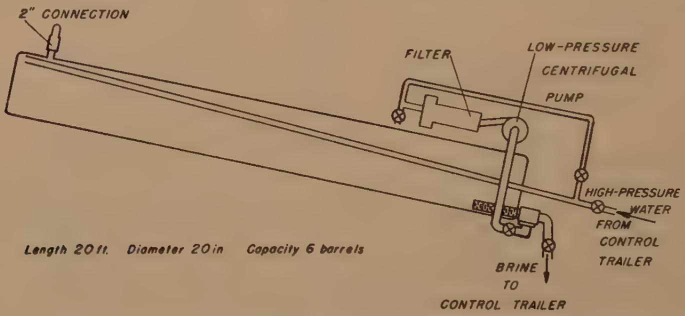

Fig 6—Lubricator for mixing and high-pressure injecting of brine.

convenience and delicate control of the flow rate all or part of this water passes through several other orifices fitted with high-pressure manometers from which the instantaneous flow rates are obtained.

Fig 6 illustrates diagrammatically the high-pressure tank trailer. At the top of this tank solid rock salt is introduced and dissolved between brine injections by means of a low-pressure centrifugal pump pressure pump and high-pressure water is introduced at the top of the tank thereby providing a source of high-pressure brine at the bottom. The brine enters the control trailer as shown in the flowsheet, Fig 4, where it passes through orifices for measuring and regulating its flow to the well In the control trailer it may also be diluted with fresh water in order to obtain the needed volume at the required concentra-

tion. Here, also, it passes through a spark plug-conductivity cell by which its dilution can be followed.

The brine is introduced into the well through a string of ¾-in. pipe on the bottom of which sections of probe pipe are attached. This probe serves not only to conduct the brine to the bottom of the well but also serves as a series of electrical stations at one-foot intervals at which conductivity measurements can be made to determine the location of the fresh water-brine boundary on the outside of the probe. The contact for these measurements must be made from the inside through the pipe to register the conductivity on the outside. Since steel pipe is used for structural strength a rather unique insulation and conductive design is employed. This probe may appear complicated but it eliminates the running of two parallel strings of pipe inside the regular 1½ to 2-in. well tubing or it eliminates running a multiconductor cable from many conductivity stations parallel to the special brine-injection tubing.

A sufficient length of this probe is made up from 3-ft sections of steel pipe, illustrated in Fig 2, to cover the formation under investigation. This probe has undergone considerable modification to afford mechanical strength as well as the required sensitivity. The model illustrated works satisfactorily although improvements in sensitivity are still being made. In order to achieve the desired strength the present model was built about sections of cold-rolled steel pipe insulated completely on the inside and at one-foot intervals on the outside. Insulated connections are made from a brass ring on the outside to the corresponding ring on the inside.

A No. 14 well cable of 7-strand Synthanol covered copper wire carries a contactor to the inside rings in the probe. Since the brine column carried through the probe actually short circuits the inside rings by forming an electrical connection between them, the contactor as well as the probe must be designed to minimize this leakage current. The contactor is designed about a 3-ft section of insulating "Synthane" tubing of a size which will just pass through the inside rings. The tube is streamlined on the ends for uninterrupted passage and is weighted at the bottom with a 10 ft length of ¼ or ⅛-in. pipe. The electric well cable is tied to the inside of the contactor tube at its highest point with stainless steel wire without breaking the insulation of the well cable. The hole through the center of the contactor is kept as large as possible so as to conduct 100 bbl per day or more of brine through its center with the smallest possible obstruction. The cable extends halfway into the contactor tube, its insulation being removed at the point at which it passes through the contactor tube wall. Here it is soldered to a ring from which three spring clip-type feelers operate to contact the inside rings in the probe. The contactor serves not only to bring the end of the well cable into direct contact with the ring but also as a means of reducing the leakage due to the brine column around the ring under contact.

In order to further reduce the leakage current through the brine column the concentration of brine used is kept down to about 0.1 pct salt where the conductivity as measured with this probe shows the maximum difference between fresh water and brine. The required use of such a weak brine has the advantage of a smaller effect on the input rate of the individual sands[4,5,6] and hence, the data is more representative of fresh water. The possibility of high dilution means that six barrels of high-pressure strong brine can be diluted ten or more times to yield a large volume of diluted brine when this is required. The use of a weak brine, however, has the disadvantage in that a less dense brine diffuses more readily than a strong brine and more care is necessary in obtaining data with the moving boundary runs.

Operating Techniques

Two methods are available for obtaining the profiles of a water-input well with this equipment. One is the moving brine-fresh water boundary method wherein only brine is injected to raise the boundary and, subsequently, only water is injected to lower the boundary. The other is the constant brine-fresh water boundary method in which both water and brine are injected at predetermined rates and the boundary is located after equilibrium has been reached. The moving boundary method requires two runs, an "up" and a "down" run, in order to cancel out the effect of the variability of well-bore diameter. In wells with a constant well bore, those which have not been shot, a single moving boundary should yield a satisfactory profile which would considerably lessen the time required for adequate data. The moving boundary method has the advantage of yielding a rapid survey over the center 80 pct of the intake; the top and bottom 10 pct intakes cannot be readily analyzed by this means because of the time required for the movement of the boundary and its eventual loss by diffusion. In addition, the moving boundary yields data from which well-bore diameters can be calculated whereas the constant boundary yields only the intake rates above and below the boundary.

The constant boundary has one major disadvantage in that it requires considerable time for a single reading. To obtain a profile, it is necessary to set progressive water and brine rates so that the brine-water boundary will be found at successive one foot intervals, each of which requires some time to reach equilibrium. There are two distinct advantages of the constant boundary method: first, readings can be obtained near the top and bottom of the intake zones; and, second, values can be obtained in cases where the moving boundary method cannot be used, such as wells completed with a liner or perforated anchor pipe. There are instances where the moving boundary runs give trouble because of blurring of the boundary, whereas the constant boundary technique yields some data until the difficulty can be corrected. The constant boundary technique has an additional advantage in that it affords a sharp boundary for the beginning of a moving boundary run. Neither of these methods can be readily adapted to the wells equipped with anchor packers with open collars unless this pipe could be ripped first either with a charge of explosive or other means.

Calculation of Results

Normally, both an "up" and a "down" run are required to determine a moving boundary profile. On the "up" run, brine is injected at the well head at a measured rate, Q_U, and the time required for the boundary to travel between adjacent lugs Δt_U, is measured on the conductivity chart. Likewise, on the "down" run, the rate of water injection at the well head, Q_D, and the time required for the boundary to pass successive lugs, Δt_D, are measured. The injection rates are kept as constant as possible, the time average of both rates being taken as $Q_{\text{Avg.}}$

The rate, Q_B, at which brine enters the sand below the boundary is given by:

$$Q_B = \frac{Q_{\text{Avg.}}}{1 + \dfrac{\Delta t_D}{\Delta t_U} \times \dfrac{Q_D}{Q_U}} \qquad [1]$$

The derivation of this equation has been presented in a previous paper.[3] The intake per foot of sand is the difference between the Q_B values for successive one foot lugs. A sample calculation is included as Table 1. For example, on the up run it took the boundary 23.4 min to travel from 1759 to 1758 ft, Δtu; brine was being injected at a rate of 93.5 bbl per day as determined from orifice flowmeter readings; on the down run it took the boundary 0.9 min to travel the

TABLE 1—*Sample Calculation of Water-input Profile from Moving Boundary Method*
Matson-Browntown Lease, Well No. W-31

Depth, Ft	Up		Down		$\frac{\Delta t_D}{\Delta t_u}\frac{Q_D}{Q_u}$	Q_B Bbl per Day	Intake, Bbl per Day per Foot
	Δt_u Min per Ft	Q_u Bbl per Day	Δt_D Min per Ft	Q_D Bbl per Day			
Packer, 1754							
1,759	23.4	93.5	0.9	93.5	0.0384	90.5	3.5 bbl/5 ft
1,760	6.8	93.5	0.9	93.5	0.134	82.6	7.9
1,761	7.2	94.4	1.0	93.5	0.140	82.5	0.1
1,762	9.2	94.4	1.4	93.5	0.153	81.5	1.0
1,763	5.3	94.4	1.1	93.5	0.209	77.8	3.7
1,764	4.6	94.4	1.0	93.5	0.219	77.2	0.6
1,765	3.95	94.4	0.9	93.6	0.230	76.5	0.7
1,766	3.2	94.4	0.85	93.6	0.268	74.2	2.3
1,767	2.85	94.4	0.85	93.6	0.291	72.8	1.4
1,768	2.2	94.5	0.9	93.5	0.413	66.5	6.3
1,769	2.2	94.5	0.9	93.5	0.413	66.5	0
1,770	2.3	94.5	1.1	93.5	0.483	63.3	3.2
1,771	[a]		1.0	93.4			Avg. 4.7 per ft
1,772	[a]		1.3	93.4			
1,773	1.55	94.4	1.4	93.4	0.914	49.1	
1,774	1.55	94.4	1.6	93.4	1.04	46.0	3.1
1,775	1.4	94.4	1.8	93.5	1.295	41.0	5.0

$Q_{Avg.} = 94.0$ bbl per day.

[a] The lug at 1771 ft was missed resulting in the loss of the corresponding Δt_u values between 1770 to 1771 ft and 1771 to 1772 ft and in the loss of 3 input values from 1770 to 1773 ft. The total input was 14.2 bbl per day in these 3 ft or an average of 4.7 bbl per day per foot.

The brine intake below any particular depth $= Q_B = \dfrac{Q_{Avg.}}{1 + \dfrac{\Delta t_D}{\Delta t_u}\dfrac{Q_D}{Q_u}}$

The intake in barrels per day per foot is the difference in any two successive values of Q_B.

same distance while water was injected at a rate of 93.5 bbl per day. The average injection rate throughout the period of both runs was 94.0 bbl per day. Hence, at 1759 ft;

$$Q_B = \frac{94.0}{1 + \dfrac{0.9 \times 93.5}{23.4 \times 93.5}} = \frac{94.0}{1 + 0.0384} = 90.5 \text{ bbl per day} \qquad [1]$$

Hence, 3.5 bbl (94.0 − 90.5) were injected between the packer and 1759 ft, a 5-ft interval.

The radius of the well bore, r, may also be calculated from the cross sectional area, A, obtained as one of the steps in the derivation of Eq 1.

$$A = \pi r^2 = \frac{1}{\dfrac{1}{\Delta t_D Q_D} + \dfrac{1}{\Delta t_U Q_U}} \qquad [2]$$

A sample calculation is included as Table 2. In order to obtain the area in square inches, a conversion factor of 0.561 must be used. An example of this type of calculation is included below Table 2.

In the constant boundary method, the rates of water injection above and brine injection below a definite boundary level are measured at different depths. These values are corrected to an average total intake. If values are obtained at one-foot intervals the intake per foot of sand can be obtained by subtracting the brine input at successive depths. Table 3 illustrates a sample calculation.

RESULTS OBTAINED

Fig 7 affords an excellent comparison of the results obtained with the moving and constant boundary methods. The two columns of figures represent the total intake down to the depth indicated. It should be noted that whereas the moving profile gives values at definite one foot intervals the constant boundary level is located between two lugs; thus, the figures shown in the constant boundary column are for a boundary near that level.

In Fig 8 the constant boundary runs were made with an oil-water rather than a

TABLE 2—*Sample Calculation of Well-bore Diameter*
Matson-Browntown Lease, Well No. W-31

Depth, Ft	Up		Down		$\frac{1}{\Delta t_U Q_U}$	$\frac{1}{\Delta t_D Q_D}$	Area, A, Sq In.[a]	Radius, r, In.
	Δt_U Min per Ft	Q_U Bbl per Day	Δt_D Min per Ft	Q_D Bbl per Day				
1,759	23.4	93.5	0.9	93.5	0.00054	0.01187	45.3	3.8
1,760	6.8	93.5	0.9	93.5	0.00157	0.01187	41.8	3.68
1,761	7.2	94.4	1.0	93.5	0.00128	0.0107	46.9	3.87
1,762	9.2	94.4	1.4	93.5	0.00122	0.00763	63.5	4.5
1,763	5.3	94.4	1.1	93.5	0.0020	0.0097	48.0	3.92
1,764	4.6	94.4	1.0	93.5	0.0023	0.0107	43.2	3.7[illegible]
1,765	3.95	94.4	0.9	93.6	0.00268	0.01187	40.0	3.58
1,766	3.2	94.4	0.85	93.6	0.00331	0.0126	35.2	3.35
1,767	2.85	94.4	0.85	93.6	0.00372	0.0126	34.4	3.31
1,768	2.2	94.5	0.9	93.5	0.0052	0.01187	32.9	3.22
1,769	2.2	94.5	0.9	93.5	0.0052	0.01187	32.9	3.22
1,770	2.3	94.5	1.1	93.5	0.0046	0.0097	39.2	3.54

[a] A conversion factor of 0.561 is used to convert area to sq in.
This is obtained from:

$$\frac{5.61 \text{ cu ft per bbl} \times 144 \text{ sq in. per sq ft}}{1440 \text{ min per day}} = 0.561$$

Thus:

$$A = \pi r^2 = 0.561 \times \frac{1}{\frac{1}{\Delta t_U Q_U} + \frac{1}{\Delta t_D Q_D}}$$

Example: at 1759 ft:

$$A = 0.561 \times \frac{1}{\frac{1}{23.4 \times 93.5} + \frac{1}{0.9 \times 93.5}}$$

$$A = 0.561 \times \frac{1}{0.00054 + 0.01187} = \frac{0.561}{0.01241} = 45.3 \text{ sq in.}$$

TABLE 3—*Sample Calculation Water Intake by Constant Boundary*
Matson-Browntown Lease, Well No. W-31

Depth, Ft	Measured Intakes			Adjusted Intakes[a]	
	Total, Bbl per Day	Brine, Bbl per Day	Water, Bbl per Day	Brine, Bbl per Day	Water, Bbl per Day
1,759	88.9	82.2		87.0	7.0
1,767	95.7	69.7		68.5	18.5
1,768	83.0	60.7			
1,774	92.6	43.6		44.2	49.8
1,778	95.6		72.8	22.4	71.6
1,779	93.6		75.5	18.3	75.7
1,781	91.3	12.2	85.1	12.6	81.4
1,782	94.6	6.2	88.2	6.1	87.9
1,784	94.1	2.9	91.3	2.9	91.2

[a] Brine and water intake rates were adjusted to a total intake of 94.0 bbl per day at 740 psi well head pressure.

brine-water boundary. This method has the advantage of a sharp, non-blurring boundary. Its chief disadvantage lies in the cost of the oil used. It is definitely limited to wells of very low intakes and the injection of oil into a sand has the disadvantage of affecting its subsequent water-intake rate.

Selective Acidization

To date, the instrument has been used primarily to determine the selectivity of various acidization and plugging experiments. Data have been obtained on five different leases using various plugging materials. On three of the leases the object was to plug selectively a permeable watered-out sand while at the same time increasing the intake into the tight oil sands. It should be noted that in the Bradford area there is little or no communication between strata because of the low vertical permeability and the prevalence of continuous shale breaks. In this type of experiment the total intake may remain the same after treatment or it may be increased or decreased depending on the intake rates in the various sand layers; hence, the

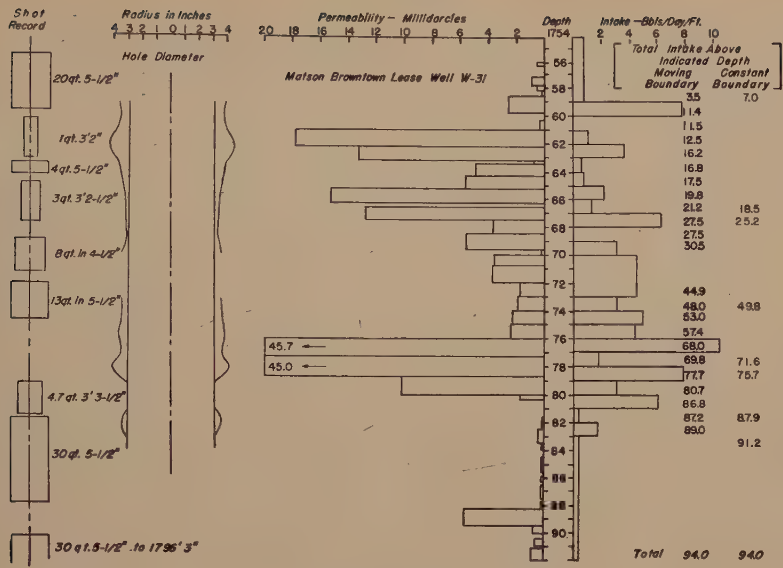

FIG 7—COMPARISON OF INTAKE RATES PER FOOT AND HOLE DIAMETER WITH PERMEABILITY AND SHOT RECORD.

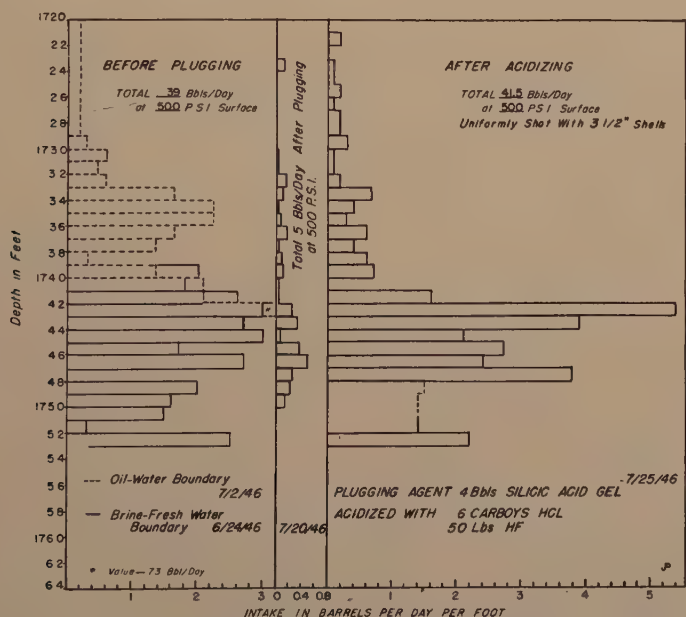

FIG 8—WATER-INPUT PROFILES BEFORE AND AFTER PLUGGING AND ACIDIZING.
Streeter Pickett Lease near Rixford, Pa.

effectiveness of the treatment cannot be determined from the total well intake. A water-input profile is the only method for determining directly the effectiveness of this type of selective plugging.

It was felt that by first plugging the watered-out sand and then acidizing, any natural plug in the more permeable sand would be augmented rather than eliminated. In addition, any slight plugging of the less permeable oil-bearing sand would be cleaned out by the subsequent acidization. Another reason for selective plugging just prior to acidizing is that with a decreased total intake the acid can be brought into a better contact with the tighter sands for a longer period of time while at the same time permitting the use of a higher pressure on the acid.

Fig 8 shows the results of both the plugging and acidizing on well No. W-14, Streeter's Pickett lease on Columbia Hill at Rixford, Pa. A 60 pct cut-back in water-intake rate was obtained on the supposedly watered-out streak above 1740 ft by selective plugging with silicic acid gel.[7] The intake of the lower oil-bearing sand was likewise increased 40 pct by the final acidization; the total intake remaining substantially the same.

Selective Plugging

Occasionally a water-input well will have an extremely high intake, hundreds of barrels of water per day. This water may be entering an extremely permeable watered-out sand, the so-called "thief" sand, or it may be entering a crevice or by-pass of some sort. This water frequently goes directly through to and beyond a neighboring producer increasing both the water-oil ratio and the pumping costs. It is, therefore, economically advisable to plug off the "thief" sand without affecting the input in the rest of the well. One of the important uses of the water-input profile is in its ability to locate such sands and to determine the effect of the plugging on the productive sands. The total water intake in the well indicates whether or not the thief sand has been plugged; it gives no indication as to the effect of the plugging on the other sands in the well.

Data were obtained with the profile instrument before and after plugging two of such abnormally high intake wells. On the Williams Producing Company's Kaber and Coulter property, intake well No. W-15 at Gifford, Pa. was plugged with two different plugging materials. This well was in an area of high oil saturation and high permeability. This well had increased in intake during May and June 1946, from 300 to 1000 bbl per day at the same pressure. The well was equipped with an anchor packer set on a 4¼-in. liner with four perforations per foot down to 2040 ft; hence, it was impossible to obtain a moving boundary profile. The by-passing streak in this well was located just below the packer and above the upper sand. It was thought to be a crevice, a fracture or a failure in the packer. The first plugging material tried had been used successfully to plug loose sands. It plugged only the sands below the by-passing streak without affecting this strata and was accordingly removed with caustic. Two separate preparations of a coarse oil-base plugging material were tried. The second preparation formed a permanent plug which could not be made to fail by a pressure drop and backflow. This reduced the total intake of the well from 1000 bbl per day to slightly below 100 bbl per day at a pressure of 900 psi with all of the intake in the sands below 2025 ft.

Although only fragmentary data were obtained on this well, as indicated in Table 4, the water-input profile instrument was useful not only in locating the high intake section but primarily in indicating that the first plugging material had plugged only the sands whereas the second plugging material apparently had not affected them. If the profile instrument had not been used the first plugging material might uninten-

TABLE 4—*Comparison of Water Intakes Before and After Plugging*
Williams Producing Company, Well No. W-15

Depth, Ft	Before Plugging				After Emulsion Plugging				After Oil-base Plugging			
	Pressure, psi	Total Intake, Bbl per Day	Intake Below Boundary		Pressure, psi	Total Intake, Bbl per Day	Intake Below Boundary		Pressure, psi	Total Intake, Bbl per Day	Intake Below Boundary	
			Bbl per Day	Pct			Bbl per Day	Pct			Bbl per Day	Pct
2,010		[a]			Thief sand between 2008–2024 ft		221.	92.0				
2,025					37	240	19.	8.0	880	71.4	71.4	100
2,030									880	76.7	44.7	58
2,035	10	38.5	21	55	37	240	17.	7.2				
2,038	10	39.5	14	35					880	89.6	12.0	13.5
2,039	10	39.0	8.2	21								

[a] An attempted moving boundary profile showed considerable intake in section just below packer. Packer set at 2008 ft; 4¼ in. liner perforated four times at each foot of depth down to 2040 ft. Chip core shows most permeable sands between 2022 and 2036 ft. Shot recommendation below 2036 ft.

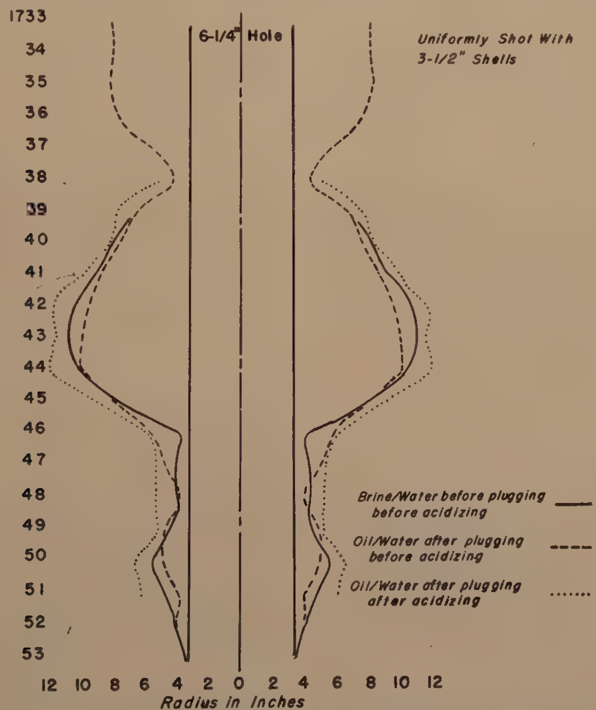

FIG 9—SHOT-HOLE DIAMETERS OBTAINED WITH TWO METHODS BY WATER-PROFILE EQUIPMENT.
Pickett Lease Well No. W-14.

tionally have been left in the oil-producing sands with some decrease in water input and production. As a result of this one test the company was able to treat similarly all other high input wells on the lease with very beneficial results.

Well-bore Diameters—Selective Shooting

Well-bore diameters were calculated on three wells by use of Eq 2. Two of these are shown in Fig 7 and 9. In general from good moving boundary profile data, the

well-bore diameters as calculated from different runs do not vary more than 2 to 3 pct. Some approximate well-bore diameters, shown in Fig 9, were obtained from the oil-water constant boundary data in which definite amounts of oil were introduced in the well to lower the boundary one foot at a time. The results of these data obtained by direct displacement compare favorably with those obtained as outlined above by an entirely different procedure.

Since the bore-hole diameters, which are determined with the same data from which the moving boundary water-input profiles are calculated, are not affected by plugging or acidizing, these diameters are of value in demonstrating the accuracy of the profiles. They are offered here only as an indication of the possibilities inherent in the use of the water-profile instrument as a hole caliber device in selective shooting experiments.

As mentioned previously almost all wells in the Pennsylvania area are shot with nitroglycerine to increase the intake rates in the less permeable strata. The vertical permeability of the sands in this region is relatively small and in addition the various sand strata are separated by impermeable shale layers. This requires an adequate water input into each sand strata. Originally the wells were shot uniformly but in recent years the trend has been toward selective shooting with shells of varying diameters and capacities for sands of varying permeabilities. The water-input profile instrument has provided a means for determining the effect of various types of selective shooting in increasing the water-intake rates of the tight sands. This increase is shown by a comparison of the intakes in the various sand layers with the permeabilities and shot patterns as shown in Fig 7. It can be seen that some of the less permeable sands, at depths of 1759 ft, 1769 to 1776 ft, and 1780 to 1781 ft, shot with 3½-in. shells or greater have intakes almost as high or higher than some of the more permeable sands at depths 1761 to 1763 ft, 1765 to 1767 ft, and 1776 to 1779 ft which were shot only lightly or not at all.

A comparison of the well-bore diameters with the size and type of shot may indicate the direction of the maximum shot effect as shown in Fig 7. The enlargements in bore diameters at certain depths may be caused by the meeting of shock waves; i.e., zones of maximum force or directed pressure, at these depths during the explosion. Fig 7 shows the maximum bore diameters located in the areas between large shells. The extreme differences in bore diameters indicated in Fig 7 and 9 may be caused by the difference between a uniform shot and selective shooting.

Insufficient runs have been made to date to draw definite conclusions with respect to oil-well shooting. As more water-input profiles are taken, a quantitative evaluation of the efficiency of selective-shooting experiments might be obtained. It is planned to take measurements on new wells both prior to and after selective shooting to supplement this information.

Summary and Conclusions

A brine-fresh water boundary can be used to obtain the input profile of a water-injection well by two different methods: a moving boundary method in which only one fluid is injected at a time and a constant boundary method in which both fluids are injected at fixed rates.

This instrument has three primary advantages: the probe can be inserted through 1½ or 2-in. tubing, the type of completion available in water-intake wells; inputs as small as ½ and 1 bbl per day per foot of sand can be differentiated; the effect of a variability in well-bore diameter caused by shooting the well can be determined and/or cancelled out with an "up" and a "down" run in the moving boundary method. The constant boundary method yields information irrespective of the changes in hole diameter.

It serves an extremely useful purpose as a research tool in diagnosing unfavorable conditions of the distribution of intake into various strata and evaluating corrective measures such as selective acidizing, selective plugging and selective shooting. As a service tool its use would be less limited.

It has been used successfully to chart the rearrangement of the water input in three wells, one of which is described. In each of these wells it was desired to decrease the input in a supposedly watered-out strata of high permeability by selective plugging while at the same time increasing the input in other strata of tight sand by selective acidizing. Since the total intake of the well described was essentially unaffected, the only means of determining the success of these treatments was by a graph of the water input of the sands as provided by this instrument.

Its use is also described in successfully locating and plugging a stratum of extremely high intake, close to 1000 bbl per day, and in determining the effect of various plugging materials both on this stratum and on the remaining sands whose intake should not have been affected by the plugging material.

Other data are presented which point out the possible use of this instrument in determining the direction and effectiveness of various types of selective shooting and in illustrating how the hole diameter varies with type of shot. The favorable results of brine and acid on the conductivity of sands[5,6] indicate that experimental selective shots should be carried out using an acid water or concentrated brine tamp rather than a fresh-water tamp. With the use of recently developed upside down hook-wall packers capable of withstanding high pressures without the use of cement it appears practical to conduct such input-profile experiments before and after various types of selective shot techniques.

Acknowledgments

The author wishes to thank the Pennsylvania Grade Crude Oil Association under whose production research program this technique was developed. He wishes to thank Dr. R. V. Hughes, Director of research of this Association for permission to publish this paper. Thanks are due Messrs. David Evans, Eugene Bowler and Robert Neal who have worked on this project as members of the Association's research laboratory during the last two and one-half years. The author wishes to thank John Calhoun and Robert McCormick who worked with the author under the Secondary Recovery Research Program of the Pennsylvania State College in the original development of this technique. Mr. John Calhoun's interest and his derivation of the method of calculation for the moving boundary runs deserves special mention. The author also wishes to thank Mr. J. P. Jones for his interest and assistance with the mechanical details and construction of the equipment and Mrs. June Pfister for calculations on many sets of data and her help in preparing this paper.

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DISCUSSION

Lincoln F. Elkins*—The author has shown that it has been possible to determine the

* The Standard Oil Co. (Ohio), Oklahoma City, Okla.

water-input profile of a well, correct it by selective shooting, selective plugging, and selective acidizing, and then to determine effectiveness of the corrective measures. I should like to ask Mr. Pfister if production performance of offset wells has borne out the results of altering the input profile of wells. In other words, are the permeable zones separate from each other so that control of input profile will extend to the producing wells, or do the permeable zones grade into each other so that input profile control is effective over only that area in the general vicinity of the input well?

R. J. Pfister (author's reply)—I am sorry to report that I have no production performance data on offset wells. This is due to the relatively small amount of regular gauging of oil and water which is carried out on individual wells in the Bradford area.

Gauging of oil and water is not generally carried out on individual wells in the Bradford area; hence, little producing data has been available to check the effect of input well treatment on producing wells. However, on the Williams Lease a well similar to W-15 also required plugging but this well was not profiled. After plugging it was reported that a producing well on a neighboring lease changed from pumping almost all water to pumping all oil. It should be noted that the treatment of one input well in a five-spot may affect any or all four neighboring producing wells or it may affect a more distant producer. It is generally demonstrated by closely spaced core wells, electric logs, and the like, that the various permeable strata are continuous from one well to another and that they are separated from each by definite and continuous shale breaks.

W. B. Berwald*—The instrument and procedures described by the author are very interesting and offer means by which desirable information in respect to the behavior of water-input wells may be obtained, particularly in operations where small diameter tubing is used in the injection well.

To one not too familiar with this type of instrument and the procedures employed in its use, more explanation by the author would be desirable. It is not clear how the up and down runs with the moving boundary are used to calculate the well-bore diameter, or how this diameter may be cancelled out. Nor is it clear how the constant boundary method yields reliable information, irrespective of changes in hole diameter. After some study of the methods and calculations involved, I feel sure that such conclusions are correct but more detailed discussion of these points would be helpful to the average reader.

Although the equipment that has been described is primarily for research work it would seem to offer good possibilities for development into service work. In this connection additional field tests would seem desirable, particularly on producing formations with much higher permeabilities than those of the Bradford sand.

R. J. Pfister (author's reply)—It was requested that the paper be shortened; hence, a detailed discussion of the method of calculation was omitted from the paper. The derivation of the formulas used to calculate the input from two moving boundary runs were previously reported.[8] This derivation shows clearly that the well-bore diameter has been cancelled out. In the constant boundary runs the brine boundary serves almost like a packer. The intakes above and below this boundary are independent of the hole diameter. In other words, once the boundary has found its equilibrium position the amount of fluid to fill the hole is fixed and no more is required to move the boundary. Thus, at equilibrium, the total input is divided into only two fractions: that entering above and that entering below the boundary.

Regarding further application of this instrument it may be pointed out that this equipment is still in constant use and still under development in hopes of getting information on more wells[8] and improving and speeding up the measurements.

E. P. Bowler*—While associated with the Pennsylvania Grade Crude Oil Research Staff in 1946, I had the pleasure of working with Dr.

* The Ohio Oil Co., Findlay, Ohio.

[8] R. J. Pfister and D. L. Evans: Stratigraphic Rearrangement of Water Rates in Input Wells. *Producers Monthly* (Oct. 1947) **11**, No. 12, 14–20.

* U. S. Naval Technical Office, American Embassy, Cairo, Eygpt.

Pfister conducting experiments with the water-input profile measuring instrument described in his paper. Dr. Pfister's profile device was designed for the introduction of brine and fresh water into an input well and his procedures and reporting deal solely with this type of survey.

The basic method of measuring input profiles by a "located two fluid interface" as first proposed in 1941,[1] advocated using a constant boundary with crude oil and water as the opposing fluids. These fluids had been selected as being the most ideal after considerable study and experimentation. The purpose of submitting this discussion is to give the producer a clearer conception of the problem by defending the use of crude oil in securing profile data in order that he may be in a better position to evaluate the various processes. It is my opinion that a survey method using an oil-water interface is well worth investigating by an aggressive water-flood group who are out to get the job done.

During the time I worked with the Pennsylvania Grade we ran rather brief and improvised oil-water interface experiments on one well using Dr. Pfister's contrivance with what I considered very encouraging results; however, the existing design of the instrument did not provide sufficient crude oil storage to complete the profile run in one continuous operation. Partial results obtained in these relatively brief experiments are listed in Fig 8 and 9 of the paper. These were the only tests ever conducted with the described instrument using oil and water.

It is noted that Dr. Pfister in his paper discredits the use of the oil-water interface method as uneconomical and impracticable. These statements to my mind are not justified nor can they be substantiated.

The advantage of using an oil-water interface lies chiefly in the simplicity of its operation. It requires very few recording devices, its control is much less delicate than it is with a water-brine boundary, and it can be operated very rapidly because of the clear-cut undefileable interface. Another advantage is that it will give a complete picture of the entire sand body if so desired; whereas, with a water-brine interface it is very difficult, if not impossible, to determine the upper and lower portions of the sand profile by the moving boundary method owing to the rapidity with which the interface moves in these sections when reversed, not allowing sufficient time to get the moving contactor on the succeeding lug, also, because the interface in these sections is often blurred. A clear-cut interface is mandatory especially with a moving boundary where critical data is the time required for the interface to move between lugs. Because of the sensitivity of the water-brine interface many man-hours are required to obtain satisfactory results, thus neutralizing any economical advantage in using these fluids.

The simplicity of mechanical operation in using an oil-water interface will contribute greatly toward making this instrument available to the average water-flood producer as a well servicing aid in much the same way as Dowell supplies this type of service to the flush producer with the electric pilot.[9] To date the instrument as described by the paper under discussion has been used only as a research tool on a few wells in the Bradford field.

The specific disadvantages cited by Dr. Pfister in the use of oil and water are:

1. It is definitely limited to wells of very low intake because of excessive cost of the crude oil used.

2. The injection of oil into the sand permanently affects the subsequent water intake rate of the well.

Because of the absence of concrete data certain reasonable approximations will have to be made in considering the first disadvantage.

Assume that an oil-water profile test is being made on a well in the Bradford field which normally is taking 150 bbl of water per day (an abnormal condition), that the water is entering the sand at a uniform rate throughout its entire depth, and the well contains 40 ft of productive formation. The number of 1-ft readings required would be 40, the average time of each reading can be taken as 15 min. maximum which is a very fair assumption based on actual field experience. Assume a sufficient supply of crude oil is available to complete the run in one continuous operation, that the average time required for each reading is approximately the same, and that the average rate of penetration of Bradford crude into

[9] L. B. Swan: The Electric Pilot in Permeability Surveys. *Oil Weekly* (March 3, 1947).

the formation throughout the test is one-half that of water.

The duration of the test would be $\frac{40 \times 15}{60}$ or 10 running hours. As there is no oil injected at the start of the test, and all oil at the completion, the intake rate may be averaged. The amount of oil required to complete the test would be $\frac{150 \times 10}{2 \times 2 \times 24}$ or approximately 15½ bbl. Discounting the fact that some of the crude oil used in the experiment will back flow out of the formations, especially the tight ones, and will be flushed to the surface and salvaged, and also that a portion of the oil that enters the pay sand may eventually find its way to a producing well, the maximum cost of crude required by such a well test would be about 15½ bbl. at $5.00 a barrel or $77.50. This estimate is certainly not excessive when it is considered that one run will give complete and conclusive profile data on a well taking 150 bbl per day of water. A well with a lower intake rate would cost proportionately less.

The second disadvantage listed by Dr. Pfister is that the injected crude oil tends to permanently affect the subsequent water intake rate of the well. Crude oil, a natural associate of the sand, may slightly reduce the water input temporarily because of the higher viscosity of the oil plus a minor condition inherent to heterogeneous fluid flow, however, the duration of this condition should be very short as subsequent water injection would soon dissipate the oil throughout the formation. There is no more reason to believe that crude oil will permanently reduce the flow of water in an input well to an appreciable degree any more than it does in a sandstone core alternately flooded in the laboratory with water and indigenous crude oil. To my knowledge this condition has never occurred.

R. J. Pfister—As mentioned by Mr. Bowler, the test using oil-water was made on one well during the early stages of development of the water profile instrument. This test was slipped into the regular program unofficially. Had more tests been made available and the procedure refined to obtain more accurate data, one might have been able to report unmistakably better results and easier operation than with the brine-water boundary. The actual data obtained, however, were less accurate than the brine-water data; e.g., variations in well-bore diameter calculated from different runs were 20 pct with the oil-water and only 1 to 3 pct with brine-water, see Fig 9. The author would have been happy to have made further tests using the oil-water boundary for determining water-intake profiles but it was officially decided to use brine and fresh water.

It might be possible to design an instrument for use with oil-water whose simplicity and speed may offset the cost of oil and thus, as Mr. Bowler stated, be of more benefit to the average operator as a well-servicing aid; however, this was outside the scope of the Pennsylvania Grade research project.

It might be mentioned here that in recent work on high intake wells time differentials as small as ¼ min. have been measured with reasonable accuracy, thus extending the range of the instrument into the upper and lower portions of the sand profile. The combination of constant and moving boundaries as now used will cover the entire range. Thus, complete data can be obtained with either type of boundary. This combination of moving and constant boundary with the brine-fresh water method was developed after Mr. Bowler left the laboratory.

With this method, the decrease in time required for an oil-water boundary did not offset the increased price of oil. In using this instrument as a research tool, to which this laboratory has been limited, many runs are made before and after each type of well treatment, thus the price of oil becomes an important factor. The decrease in time required is caused primarily by the fact that a sharp boundary may be obtained immediately with oil-water, whereas several hours may be required to obtain the initial sharp brine-water boundary. Once this boundary is obtained an up and a down run may be made in one 8-hr day on wells with an input of 50 bbl per day and in proportionately less time on wells with higher intakes. The discrepancy in time is less and that in cost is greater in wells of higher intake.

The objection to the use of crude oil prevalent in this region is based on its alleged tendency to permanently or temporarily affect the subsequent input of the well. Relative

permeability measurements on cores would lead one to expect that the water permeability would be temporarily affected by an increase in oil saturation of the sands near the bore hole. The author has no data to show to what extent the throughput rates of various sand strata are affected by injection of oil, but it may be surmised that the tighter sands will be affected over a longer period of time.

A test has recently been planned to determine water input profiles before and after shooting. The author has recommended that the results of the water-brine profiles be checked with the oil-water boundary method. If the total intake of the well is exceedingly low, it may be more difficult or impossible to get readings with brine and water because of diffusion and the time required to attain equilibrium; hence, in this instance, there will be an undebatable advantage of using oil. In this test, one may also observe the extent and duration of the change in intake and profile effected by injecting oil in the well.

Location of Points of Water Entry in Oil Wells

By D. Silverman* and A. R. Brown,* Members AIME

(Denver, Tulsa and Los Angeles Meetings, 1947)

Abstract

Equipment and methods for locating the points of entry of salt water into oil wells are described. These techniques make it possible to delineate accurately the top and bottom boundaries of water zones whether bottom water or intermediate zones of production. Data are given on tests by this survey method on a number of producing wells. Complete results were obtained on wells showing water percentages ranging from high values to as little as 10 pct salt water. A number of the wells tested were plugged back and the results are reported in detail. While not all the workovers were successful, evidence, including the results of reruns by this survey method, points to failure of the plugback operations. The data provided in the tests discussed show, contrary to general opinion, that a large percentage approaching 50 pct of the wells showed intermediate water instead of bottom water. Furthermore, approximately a third of the wells tested showed multiple zones of water production.

The equipment comprises a long pipelike assembly carrying 10 pairs of electrodes spaced apart a distance of 4 ft. A surface-controlled solenoid-operated switch is provided to connect each of the individual pairs of electrodes in turn to a single-conductor steel-armored cable by means of which the conductivity of the fluid in the vicinity of each of the electrode pairs can be continuously recorded at the surface. Any number of electrode pairs and any spacing can be used. This assembly is lowered on tubing and placed in position opposite the section of the well to be studied. A conventional rod pump is used to produce the well for the survey. The pump inlet is placed below the lowest electrode pair. The well is conditioned by pumping out the salt water normally standing in the well and introducing fresh water into the annulus at the surface. When the resistivity of the water standing in the well has been increased to a sufficiently high value, the inflowing fresh water is stopped and the drawdown operation of the survey is started. As the fluid head is lowered by pumping, fluids flow into the well and the entry of salt water is indicated by the change in resistivity of the fresh water opposite the zones of water entry.

The process can be repeated as often as necessary with little effort and without moving any well equipment to be sure that the fluids produced from each zone are representative of the true reservoir content.

Introduction

The oil industry has been concerned from its inception with the control of fluids entering its wells. In order to effect the greatest economy of operation and to get the greatest total production of petroleum liquids out of the ground, the flow of gas and water must be controlled and often extensive workovers are planned and carried out for this purpose. This has become even more important in recent years because of the need for the conservation of natural resources.

Whereas producing operations concerned with the original completion of a well are assisted to a great extent by a wide variety of instruments developed and perfected for that purpose, workover operations on oil wells have been greatly hindered by a lack of suitable instrumentation. The industry has searched for many years for a satisfactory instrument and process that

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would detect the character, rates of flow, and point of entry of all fluids into oil wells. A certain amount of success has been achieved in this regard, although the knowledge of well conditions that is available by the use of present instrumentation is inadequate in many cases to justify the expense of workover operations. While the general problem of fluid-entry detection includes the ability to detect, measure, and indicate the points of ingress of oil, gas and salt water, the simplest problem, and the one which will be discussed in this paper, is the detection of salt water.

The method of salt-water location which is the subject of this paper is a simple straightforward method that involves a sizeable production of fluid from the formations. It is based upon a transient test in which the well is first conditioned with a fluid miscible with salt water whose conductivity is different from that of the salt water, and then the simultaneous measurement is made of the conductivity of the conditioned well fluid at a number of points along the well bore as a function of time. The upper and lower boundaries of each zone of water production can be determined. The process can be repeated as often as necessary, with little effort and without moving any well equipment, to be sure that the fluids produced from each zone are representative of the true reservoir content.

History of Water Location

Early in the history of the development of workover operations the method of handling a problem of water ingress was to utilize the original information about the well provided at the time that the well was drilled. The most useful data were the electrical logs and other logged formation characteristics observed at the time of drilling. On the basis of these characteristics and the well's producing history, the section to be plugged would be decided. This operation in many cases has been of limited success because in the period during which the well was producing the channels through which water entered the well might be quite different from those suspected from analysis of formation characteristics alone. In other cases reliable data on formation characteristics are not even available.

One of the first procedures set up specifically for the detection of points of entry of salt water was a process in which a pair of electrodes was lowered on a conducting cable to measure at various points along the axis of the well bore the resistivity of the well fluids. Because of salt water standing in the hole, it was necessary to introduce fresh-water mud of greater density so as to displace the salt water upward and provide a well fluid which contrasted in resistivity with the water which was expected to enter. By successive steps of bailing fluid from the well to cause formation fluids to flow into the bore, and traversing the well bore with the electrodes, a record would be provided of the resistivity of the well fluid as a function of depth. In the regions opposite the salt-water entry points, the mud would be contaminated by salt water, and its resistivity would be lowered, which would be an indication of salt-water entry. Other methods patterned on this same principle utilized chemical conditioning of the salt water normally standing in the well in order to make its properties different from those of the entering salt water, so that the latter could be detected upon entry. Still another method involved conditioning the well with mud and using a photoelectric opacity meter to detect points at which the mud was diluted by entering water.

There has also been a partial attack on the problem of fluid entry based upon measurement of the permeability profile of the well. In this process well fluids are forced into the porous formations, and by metering the rate of flow into the formations as a function of depth, the permeabil-

ity of the various strata that form the walls of the well can be determined. This information, in conjunction with electric, gamma ray and neutron logs, serves to provide some information regarding the possible sections from which salt water might be entering the well.

These methods of locating the points of entry of salt water in wells were not too successful for a number of reasons:

1. The process of successively bailing and logging the hole made it difficult to gauge the proper amount of fluid withdrawal in order to bring forth the fluids from the formations. Thus, the log either failed to show any salt-water indication or the indication was too general to be of much value.

2. The motion of the electrodes tended to contaminate the well fluids opposite all producing sections, so that false indications were sometimes made.

3. In producing the well by swabbing or pumping from a point above the producing section, the contaminating salt water moved upward and therefore contaminated the conditioning fluid in the well immediately above the salt-water zones. Thus, the upper boundaries of the salt-water zones, which are quite often the most important ones, were the least well-defined.

4. The limited volume of fluid that can be withdrawn in this type of survey quite often will not result in yielding a representative sample from each producing section exposed. A salt-water column standing in a shut-in well will often contaminate otherwise clean oil zones in close proximity to the well bore.

Present Method

In view of the lack of a fully satisfactory method for the detection of points of entry of salt water and in view of the importance of this information not only to operators but also to contractors offering services in connection with the shutting off of water zones, a development program was carried on aimed at the provision of a fully satisfactory method for the detection of points of entry of salt water into wells. The apparatus to be described and the operating processes that constitute the basis of this survey method are based upon the Gillbergh[a] patents under which the Stanolind Oil and Gas Co. has an exclusive license. This method has proved satisfactory for the detection of the points of entry of salt water and is hoped will lend itself to the extension of this process to the detection of oil and gas as well.

This method has all the advantages felt to be necessary in this type of measurement such as the following:

1. It operates upon actual inflow of salt water into the well.

2. It involves pumping well fluids instead of swabbing or bailing so that a continued and sizeable flow can be provided which will prevent false indications caused by contamination of oil sands by a column of salt water standing in the well bore.

3. The well fluids are pumped from a point very low in the well bore and definitely below the regions of interest, so that salt-water flow is downward, thereby making the indicated upper boundary of the salt-water zone definite and positive.

4. A simple, clean and convenient conditioning fluid is provided which is readily available.

5. Once the well is conditioned, tests can be rerun without any chance for salt-water contamination of clean oil sections and without altering the physical setup at the well.

Equipment

A schematic diagram of the apparatus used in this salt-water entry process is

[a] J. R. Gillbergh, U. S. Patents No. 2,248,982, July 15, 1941, and No. 2,295,738, Sept. 15, 1942. International Cementers, Inc., has been granted a sublicense to practice this method commercially.

shown in Fig 1. It involves an electrode system for determining conductivity of the well fluid at a multiplicity of detecting stations, instrumentation for measuring and recording the conditions at each of the recording stations, and pumping equipment for producing the well.

The electrode system is a pipe structure containing 10 electrode pairs which are spaced vertically at 4-ft intervals. Any number of electrode pairs and any desired spacing could be used. This structure is positioned opposite the producing formation and the electrodes measure the resistivity of the fluid surrounding them. Each of the 10 electrode pairs is connected by wires inside the pipe which extend to a solenoid-operated switch, in the bottom of the structure, which connects in turn each of the separate pairs to a single-conductor shielded cable that extends to the surface. The pipe provides protection for the electrical conductors and the space in the pipe is filled with insulating oil and

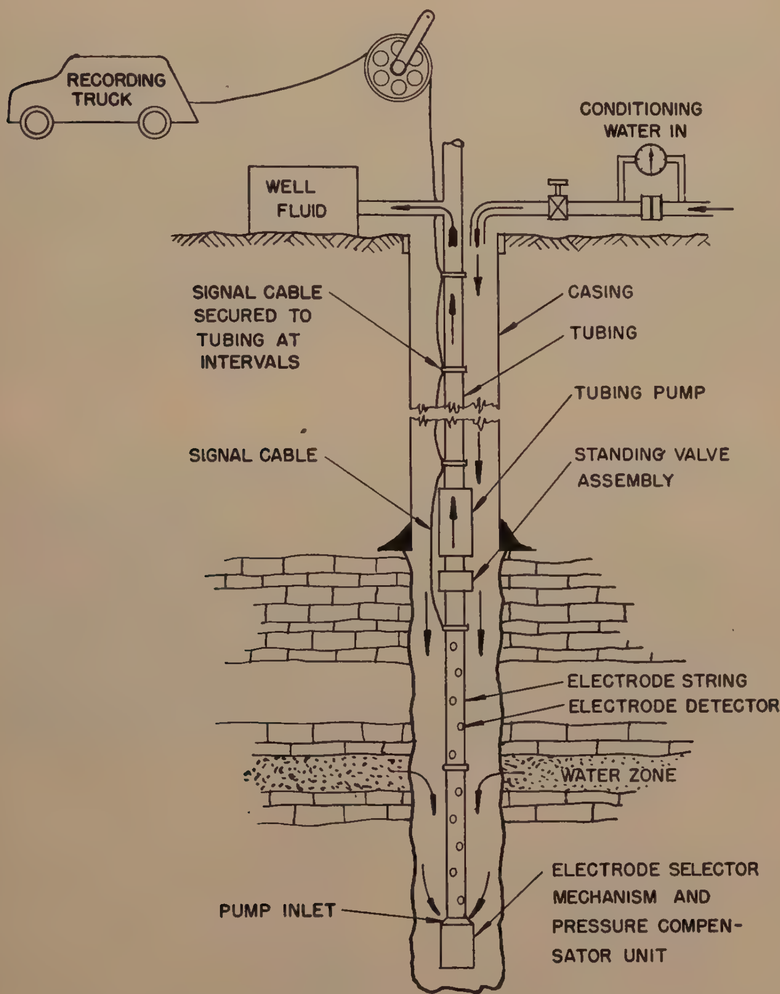

Fig 1—Schematic diagram of water entry survey apparatus.

provided with a pressure compensator. Surrounding the central pipe containing the electrodes are 4 equally spaced flow tubes which provide passage for well fluids from the pump inlet just below the lowest electrode station up to the pump which is above the electrode string. A flange joint in the middle of the electrode structure permits disassembly of the unit into 2 sections, each about 22 ft long, to facilitate handling and transportation.

Voltage pulses introduced at the surface end of the cable serve to operate the switch which carries through a complete cycle of 12 contacts in approximately 30 sec; 2½-sec intervals are allowed for each position, the first portion of each interval is taken up by the operating pulse and the remaining 2 sec are available for recording the resistivity. Following the 10 positions corresponding to each electrode station, there is a position in which the line is

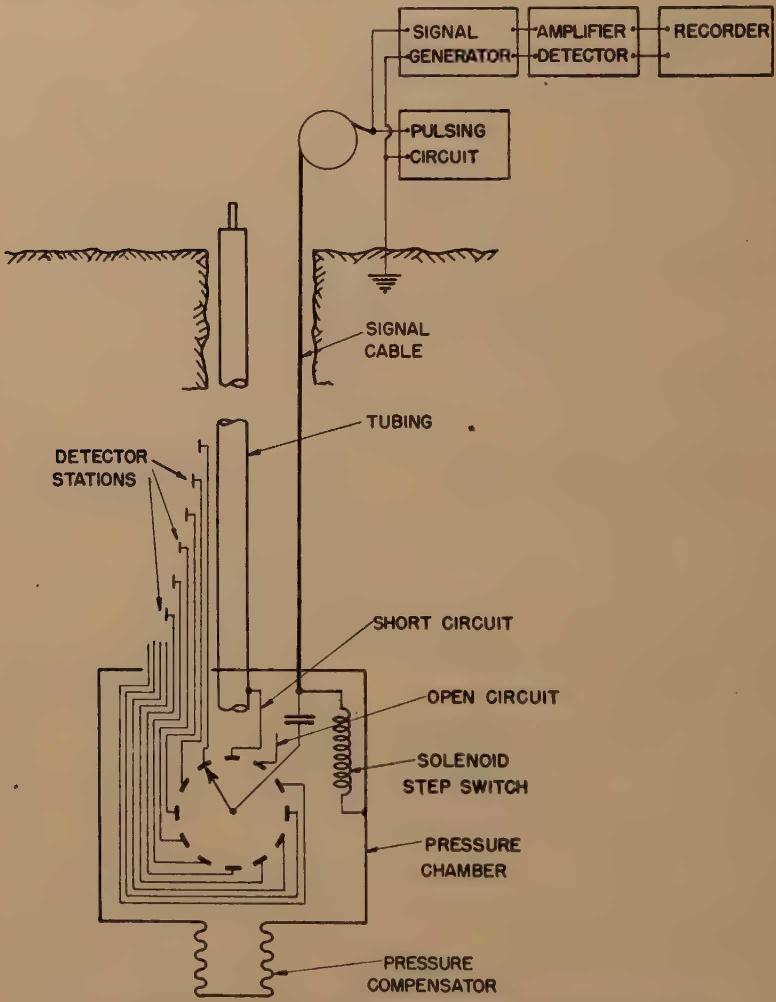

Fig 2—Detailed schematic diagram of the electrode system.

shorted and another position in which the line is opened. These two positions are for the purpose of indicating the beginning of the switching cycle and serve to identify

1. High flow rate which would reduce the time required for conditioning and would also permit flowing the well at high rates.

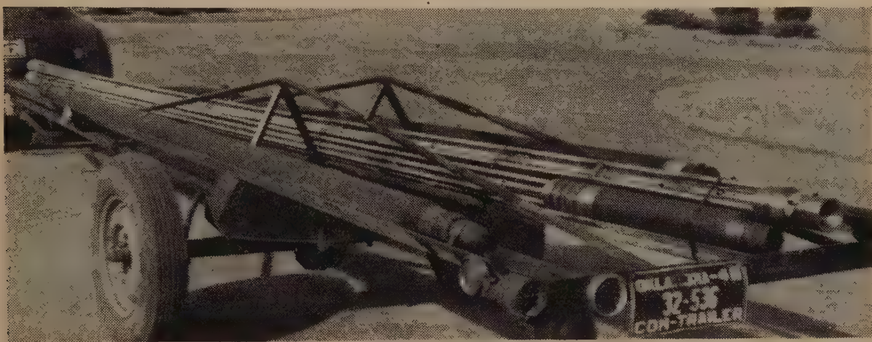

FIG 3—BOTH SECTIONS OF ELECTRODE STRING LOADED ON TRAILER WITH TWO REDA PUMPS.

FIG 4—CLOSE-UP OF BOTTOM AND TOP ENDS OF ELECTRODE STRING.
Bottom end consists of pump inlet and housing for electrode selector mechanism and pressure compensator unit. Top end consists of collar for 2-in. tubing and pothead for signal cable.

each of the 10 conducting positions. The electrode system is shown in greater detail in Fig 2, which is again schematic. Photographs of the electrode system, the individual electrodes and the electrode-selector system are shown in Fig 3, 4 and 5, respectively.

Two types of pumping systems have been tried for these operations. The conventional rod-type pump is quite suitable and in the long run has offered the least difficulty in operation. Considerable effort was made to utilize a Reda pump for this application, in view of the following possible advantages:

2. Ease of starting and stopping the pump.

3. Ease of adjustment of position of the electrodes and tubing in the hole.

4. Freedom from oscillation of the lower end of the tubing which is of possible occurrence in the case of the rod pump.

In this process of water location, it is desirable to pump from as low a point in the well as possible. In all wells tested it was found that there was considerable solid material in the lower portions of the well bore. The Reda pump was not well adapted to pumping this material and considerable difficulty was observed in the use of the

Reda pump for this application. Standard procedure now involves the use of conventional rod pumps.

Additional surface equipment involves a truck for carrying the Reda pump, motor and power cable, and a third truck carrying an engine-driven generator to supply 3-phase power for the Reda pump. In view

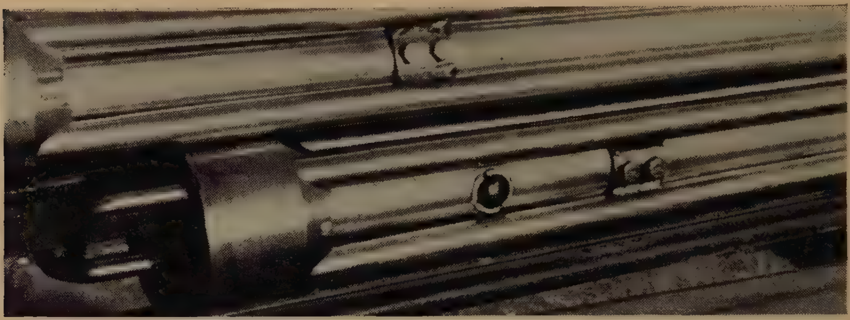

FIG 5—CLOSE-UP OF CENTER FLANGE AND ELECTRODE NO. 6.
The 4 small tubes provide passage for well fluid from pump inlet at bottom to tubing pump above electrode string.

tank of fresh water of relatively high resistivity compared to the salt water flowing into the well, and metering equipment to control the rate of flow of fresh water into the annulus of the well. Also, it is desirable to have metering equipment on the outflow line from the well pump in order to know the rate of withdrawal of fluid, both for the purpose of having an accurate determination of the production from the well and, in conjunction with the metered inflow, to maintain the bottom-hole pressure at a constant value during the conditioning period.

Surface instrumentation consists essentially of a stable low voltage current source, provision for measuring the resistivity of the water covering the electrodes, and a graphic recorder. Alternating current is used in the resistance measurements in order to eliminate polarization effects at the electrodes. The instruments are installed in an instrument truck together with a power-driven reel with a capacity of 15,000 ft of single-conductor double steel armored cable.

In work to date equipment was carried on three trucks, which included, in addition to the instrument and cable truck, a second of future reliance on the rod-type pump for this operation, the equipment has been simplified and a single truck is being used to carry all of the essential equipment for this operation.

Considerable difficulty was experienced from corrosion in the sour wells of West Texas and New Mexico. Failure of parts of the original electrode string was experienced from sulphide embrittlement. Also trouble was experienced with the armor of the signal cable due to this same cause. The electrode string was redesigned and constructed entirely of stainless steel and no further difficulties have been observed from this cause.

FIELD PROCEDURE

After all pumping equipment is out of the hole, the electrode string is assembled, filled with insulating oil and checked. The recording truck, which carries the signal cable is spotted about 150 ft from the well, and the signal cable is run from the truck over a sheave supported at about the middle of the pulling mast and then attached to the electrode string. The first joint of tubing screws directly into the top of the electrode string.

When running equipment one man operates the signal cable reel, coordinating the speed of the cable to that of the tubing. The other man works on the floor supervising handling the cable and banding it to the tubing at 300-ft intervals. A specially modified spider has a groove for the cable so that it will be out of the way of the slips. Pulling the equipment is accomplished in a similar manner. The first run is usually made with the electrode string spaced as near bottom as practical. For easy reference, the electrode positions are arbitrarily numbered from No. 1, the highest, to No. 10, the lowest.

The technique used in making a survey may be divided into three steps: (1) the conditioning, (2) the drawdown and (3) the flush. During conditioning, the tubing pump is used to remove the well fluid through the tubing, and fresh water is introduced at a controlled rate into the casing at the surface. The well is at static conditions at the start of conditioning, and is maintained at static conditions during the interchange. Since the rates of fluid withdrawal and fresh water introduced are equalized, the bottom-hole pressure is not changed and there is no fluid movement either from the formation into the well bore or from the well bore into the formation. The well is considered conditioned when a column of fresh water is placed on bottom and all electrodes are reading a high resistance.

After the well is conditioned, the introduction of fresh water is stopped but fluid removal by means of the pump is continued. This is the beginning of the drawdown and all fluid removed is taken from the annulus between tubing and casing. The pump inlet is just below No. 10 electrode so that fluid movement in the annulus is downward past all electrodes and then out through the tubing. As additional fluid is removed and the fluid head is reduced, formation fluids begin to move into the well bore. Formation water entering the well will, because of its salt content, reduce the resistivity of the fresh water and, because of fluid movement in the well bore, will move from its point of entry down to the pump inlet. If the point of entry is between two electrode pairs, say No. 8 and No. 9, all electrode pairs below the point of entry, No. 9 and No. 10, will indicate in succession a decrease in resistivity. All electrode pairs above the point of entry, No. 1 through No. 8, will remain unaffected, and the top of the water zone would be picked at No. 8 position. If the point of entry is above No. 1 position, all electrodes will be affected, making it necessary to raise the electrode assembly and repeat the tests until the point of entry is bracketed between two electrode pairs. If the point of entry is below No. 10 position, formation water entering the well bore will move directly to the pump inlet and will not be indicated by any electrodes. The presence of a water source below No. 10 position is verified by the third step, the flush.

After drawing the well down sufficiently to allow all zones in the region opposite the electrodes opportunity to produce, fluid withdrawal through the tubing is stopped by shutting down the pump. The result is that fluid in the well bore flushes upward because of production from the formation. Since fluid movement during the flush is upward, it will be indicated first by No. 10 electrode pair and then by No. 9 and progressively upward as the hole fills. In addition to checking for bottom water, the flush is used to pick the bottom of an intermediate water zone. No electrode below the water zone will be affected immediately. Salt water, because of its greater density will diffuse slowly downward, but the flush is completed before sufficient time has elapsed to allow this to affect the electrode readings.

Conditioning is the step most difficult to accomplish properly. The maximum amount of conditioning water that can be placed in a well is limited by well condi-

tions. Since practically all of the fluid removed during the drawdown to secure formation water entry is conditioning water, the more conditioning water there is in the hole at the start of the drawdown, the more representative the drawdown will be. Consequently, the amount of conditioning water desired is the maximum that can be placed under well conditions.

The column of fluid in the well is made up of a lower portion of salt water and an upper portion of oil. The height of the salt-water column in the well can be determined while running the equipment for a survey. The top of the fluid column or static fluid is usually known or can be roughly estimated. Knowing these two factors the approximate amount of conditioning water that can be placed and the time required can be determined. This is based upon observations that the conditioning water falling in the annulus will fall through the oil at a rate of approximately 600 ft per hour. This figure is an estimate and may not be too accurate, although it has been used with some success. If the well is being pumped at a rate of A feet per hour (which is determinable from the bore-hole diameter, tubing diameter and pump rate), the approximate time, T, taken for fresh water to reach the pump inlet will be $T = \frac{H - AT}{600}$ in hours, where H is the static fluid level.

Further pumping will have but little effect on the final height of the fresh-water

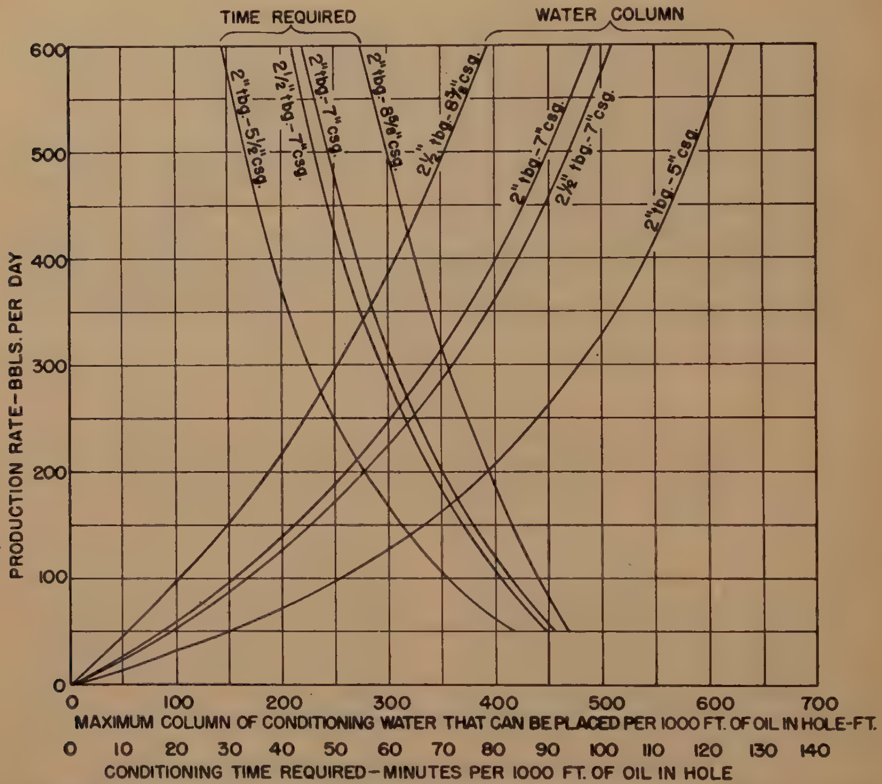

FIG 6—EFFECT OF PUMPING RATE ON CONDITIONING TIME AND HEIGHT OF COLUMN OF CONDITIONING WATER.

column since fresh water will be removed by the pump as rapidly as it reaches bottom. The next step is to stop pumping until all the fresh water has fallen through the

These relations are expressed as curves (Fig 6) from which can be read the time required for the conditioning process and the resulting column of conditioned fluid.

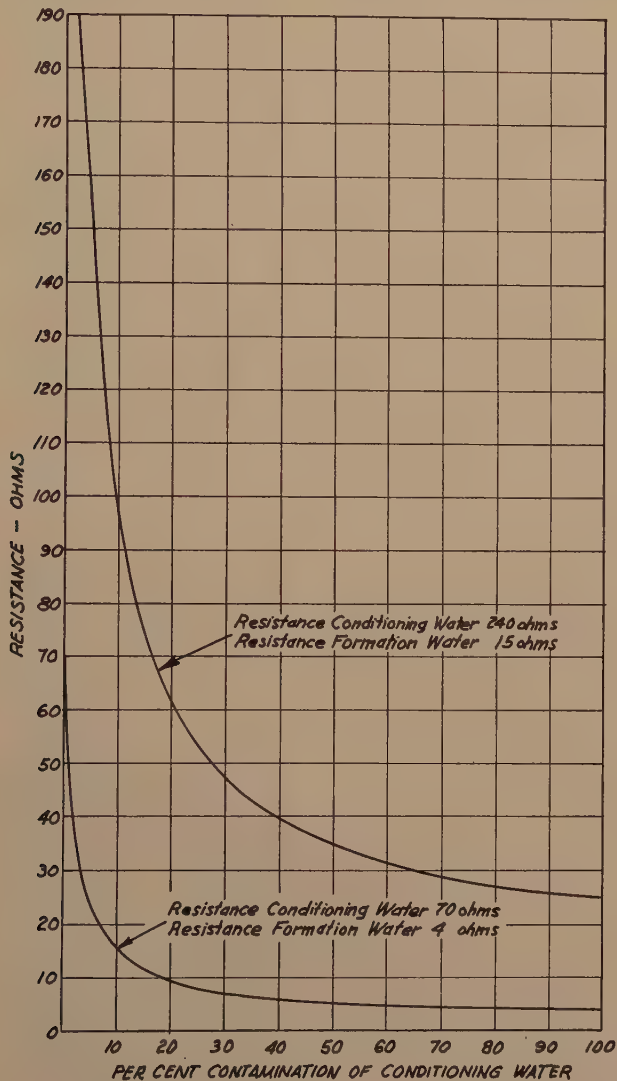

FIG 7—CHANGE IN RESISTIVITY OF CONDITIONED WATER CONTAMINATED BY FORMATION WATER.

oil. At that time, the height of the water column will be somewhat greater than AT, since the rate of fresh-water entry in barrels per hour is slightly greater than the rate of pumping of salt water.

The amount of conditioning water needed for a survey is of the order of 100 bbl or less and should not exceed 200 bbl unless an unusually large number of runs are necessary to complete the survey.

Little or no trouble is experienced in accomplishing the drawdown which normally is completed in 1 to 2 hr. The primary consideration is to be certain that sufficient time is provided to permit all water zones opportunity to produce and, if the entry is at a considerable distance above the electrode string, that sufficient time has elapsed to permit the water show to move with the fluid column down to the electrode string.

Fig 7 has been included to show the change in resistivity of conditioning water when contaminated by various percentages of formation water. The resistance of conditioning water available in the field has been found at different locations to vary from 70 to 240 ohms, for a particular electrode geometry. Similarly, formation water varies in resistance from 4 to 15 ohms for the same electrode geometry used. It may be noted from these curves that so long as the conditioning water is fresh, only slight contamination is necessary to result in a large change in resistance. This permits the detection of very small sources of water entry. Water flows of less than 5 pct of the total fluid produced have been located by this method. Check runs can be repeated as many times as desired by reconditioning and repeating the drawdown and flush. This is very important in many wells since it is often found that several hours are required to produce water out of a clean oil section if the well has been shut in with a column of salt water covering the producing sections. In view of the ease with which repeat runs may be made and the value of confirming tests, it is common practice to check the location of all water-productive zones at least a second time.

Typical Results

The type of log obtained during the Stanolind water entry survey is illustrated by the copies of two typical logs shown in Fig 8 and 9. These logs are fictitious and are drawn to show the fundamentals of the actual logs. Furthermore, they have been reproduced in reverse for greater ease of explanation. The length of time shown for the drawdown on the typical logs is about 10 min, whereas actual drawdowns cover periods of up to 1 to 2 hr. To reproduce an actual log would require 20 to 40 ft of logging paper.

It has been pointed out previously that electrode readings are taken intermittently, each electrode pair being read for about 2 sec every 30 sec. The result is a log showing a series of cycles of readings of each of the 10 electrode pairs. Each cycle is followed by a direct short circuit and an open circuit used for maintaining instrument synchronization and calibration. Readings of each electrode position are repeated in the same order in each succeeding cycle. Time proceeds from the top of the log to the bottom. Resistivity decrease denoting the presence of salt water is to the right. The record corresponding to the conditioning period is not shown on the log.

Referring to Fig 8, it may be noted that immediately after starting the drawdown, electrode pairs No. 7, No. 8, No. 9 and No. 10 began indicating the presence of salt water by their increase in deflection to the right. Since none of the electrodes above No. 7 were affected during the drawdown, there is no water entry above No. 6 and the top of the water-productive zone is picked at position No. 6. During the flush, at which time fluid movement in the hole is upward, No. 6 electrode pair immediately indicated a marked decrease in resistivity by deflection to the right. This results from a water source just below No. 6 position that flows into the hole and is indicated later by electrode pairs No. 5 and No. 4. Since electrodes No. 7, No. 8, No. 9 and No. 10 were not affected during the flush, it is concluded that there is no water entry below No. 7 electrode and the bottom of the water zone is picked at the position No. 7. The water producing zone is then defined as between positions No. 6 and No. 7

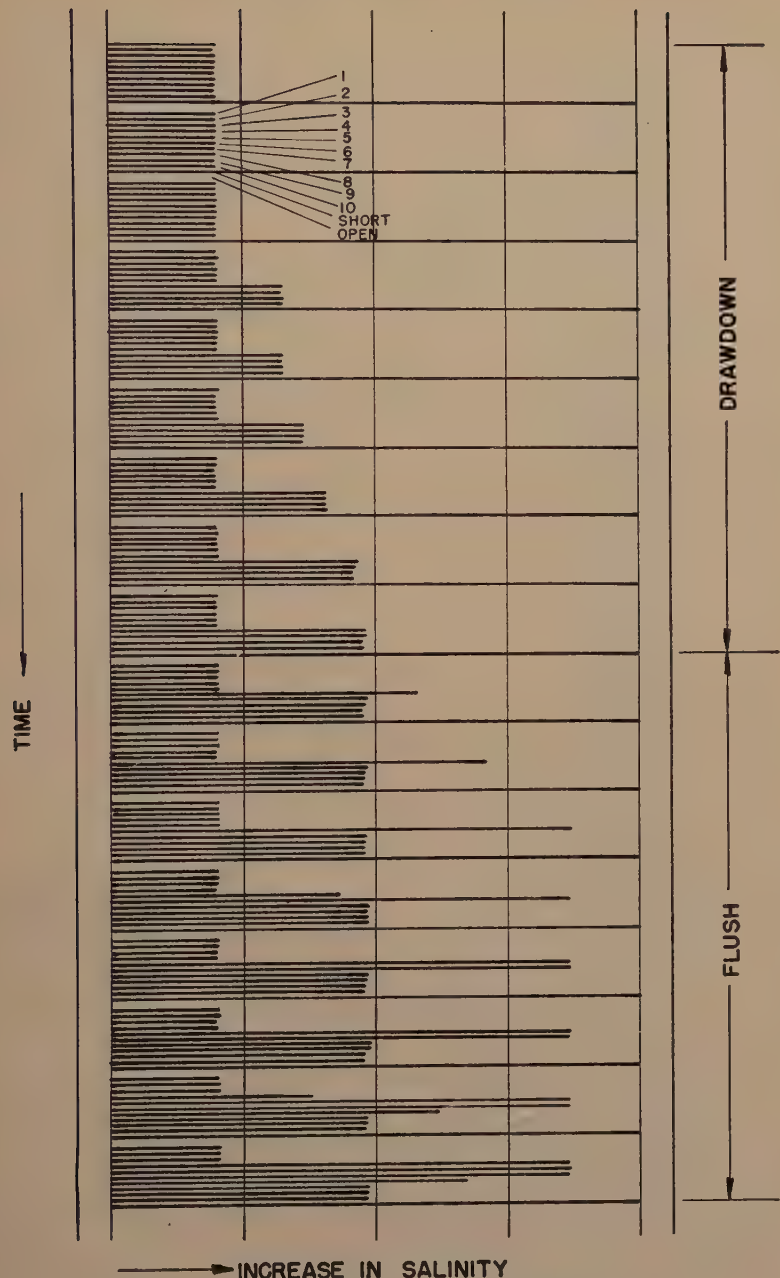

FIG 8—TYPICAL LOG OBTAINED DURING WATER ENTRY SURVEY.

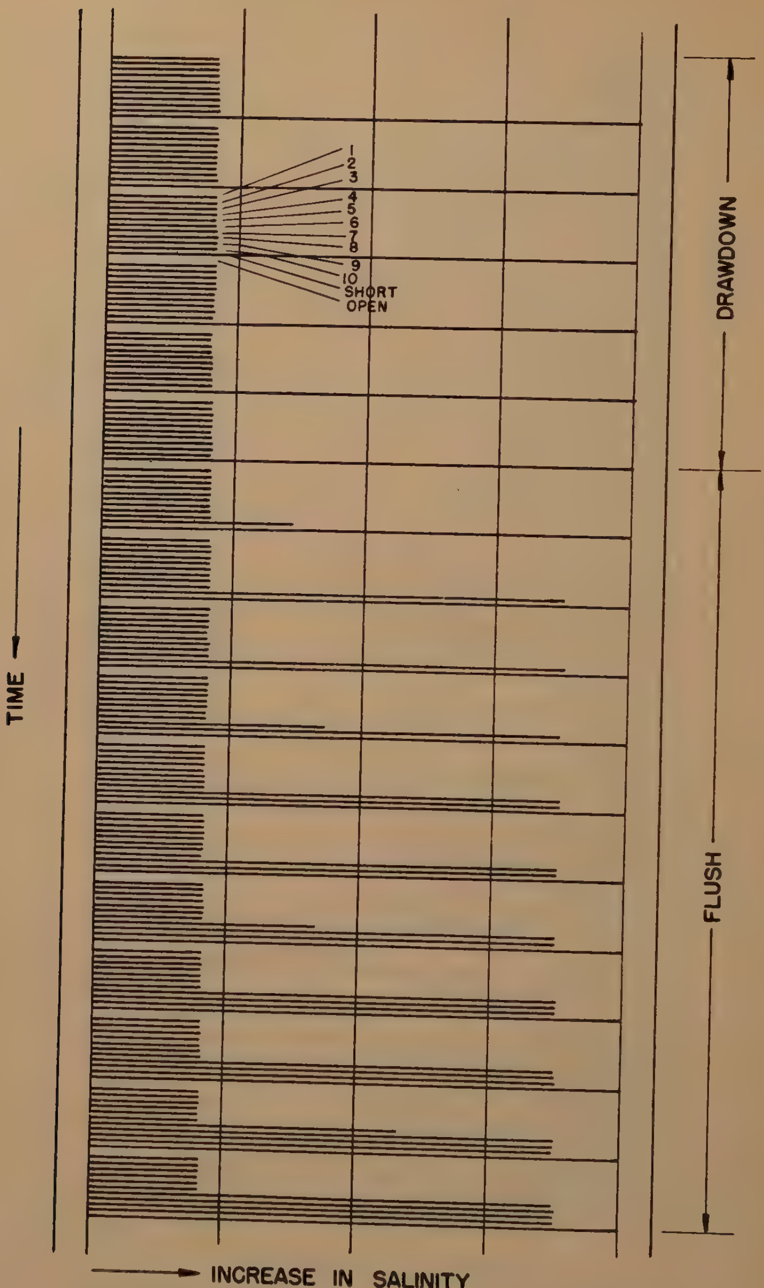

FIG 9—TYPICAL LOG WHEN ONLY BOTTOM WATER IS PRESENT.

Fig 9 is included to show the type of log obtained when only bottom water is present. It may be noted from this log that no electrode was affected during the drawdown. This indicates that there is no water entry above No. 10 position.

Immediately after starting the flush, No. 10 electrode pair showed a very marked decrease in resistance. It was followed then by No. 9, No. 8 and No. 7 as the hole filled. If the flush were continued all electrodes would eventually be covered with salt water but, since the source of water has already been determined to be below No. 10 position spaced 5 ft off bottom, it is not necessary to include any additional flush on the log.

Frequently the water source is a combination of intermediate zones and bottom water and the log is not so easily interpreted as those shown. A simpler method of presenting the results of the Stanolind water-entry survey is by means of a graph showing the *changes* in electrode readings occurring during the drawdown and during the flush. Explanation of the method of preparation and interpretation of the graph may be followed by referring to Fig 10 showing the results of an actual survey. Readings of each electrode pair are assumed to be zero at the start of the drawdown and changes are plotted opposite the electrode position at intervals during the drawdown. After 85 min of drawdown, electrode pairs No. 1 and No. 2 had not changed, indicating that there is no water entry above 4218 ft. An entry between No. 2 and No. 3 caused an increase in salinity at No. 3 and an additional entry between No. 3 and No. 4 caused an additional increase in salinity at No. 4. The increase in salinity at electrode No. 8 indicates that there is also a water entry above No. 8.

Assuming all electrode readings zero at the end of the drawdown, the changes occurring during the flush are plotted in the

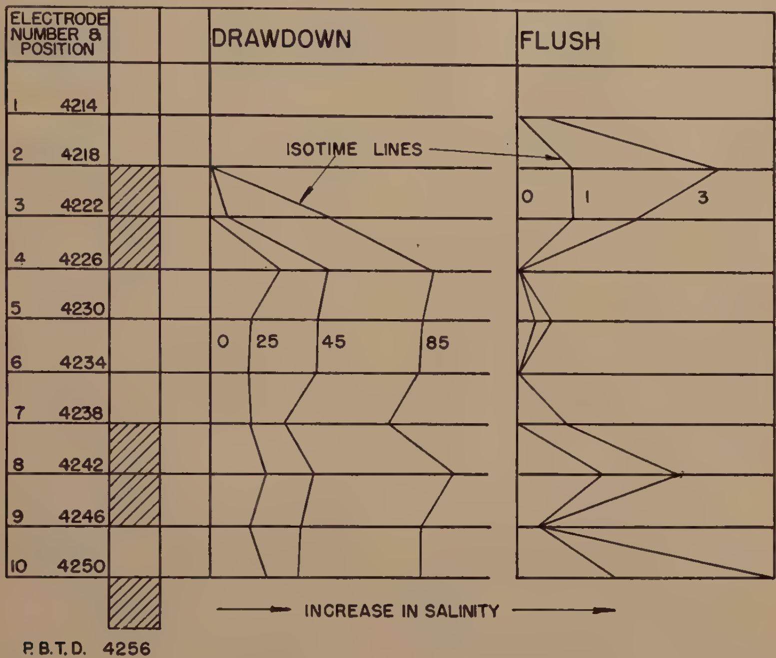

FIG 10—RESULTS OF A WATER ENTRY SURVEY.
Stanolind Oil and Gas Co. lease, State "A," tract 9, well No. 1, run No. 8.

same manner. The changes at electrode positions No. 2 and No. 3 are caused by the water entry below them. No. 4 electrode was unaffected and the bottom of this water zone is picked at No. 4 or at 4226 ft. Changes occurring at electrode positions No. 7 and No. 8 are caused by the water entry below them and the bottom of this water zone is picked at No. 9 or at 4246 ft. The large change shown at position No. 10 results from a source below it and determines the third water productive zone at 4250 ft to the plugged back total depth (P.B.T.D.) of 4256 ft. Because water from this latter source entered the well bore and moved directly to the pump inlet during the drawdown, its presence was not detected by any electrode during the drawdown. This bottom zone could be, of course, a leaking plug.

Results of Surveys

A summary of results of this water entry process on the most recent group of wells tested is shown in Table 1. The statistics shown in this table reflect that out of 9 wells tested where workovers might have been contemplated to shut off water:

1. Two workovers were not performed specificially because the location of the water-entry points was such that it would have been impossible to shut off the water without shutting off most of the oil production.

2. One well where water was located was not worked over because the water source exhausted before the well was to be worked on.

3. Out of 6 wells, workovers specifically to reduce or eliminate water production, 4 were successfully completed and 2 were unsuccessful.

The reason for the unsuccessful workovers is not definitely known; however, it is noted that well No. 6 was unsuccessfully worked over on the first attempt and a second survey by the water locating instrument indicated that the plug was leaking. A second plugback with the specific purpose of correcting the leak around the first plug eliminated most of the water production to the extent that the workover could be considered successful. It is altogether possible that mechanical failure on the two unsuccessful workovers may be the reason for not accomplishing a water shutoff.

Wells No. 1 and 2 were surveyed only to check the mechanical aspects of the survey equipment. The wells were selected because they were geographically close to the research laboratory and produced a large volume of water.

Of the 9 remaining wells which, in general, were picked at random in several West Texas and New Mexico fields, 6 wells had water-entry points scattered up and down over the pay section or had single entries substantially *above* the total depth of the well. The other 3 wells had water entering in the *lowermost* section penetrated.

The results of these tests on 11 wells are interesting in view of current ideas as to the common type of water entry. These conclusions may be summarized as follows:

1. Of the 11 wells, 5 showed *bottom water only*. (It is to be remembered that of the 11 wells, 9 were picked at random. Two whose conditions were fully known before the surveys were picked because of geographical location. If only 9 wells are to be considered as having been picked at random, the number that showed bottom water only was 3.)

2. Of the 11 wells 1 showed *bottom water in combination with intermediate water* (3 zones).

3. Of the 11 wells, 5 showed water *not coming from the bottom.*

4. Of the 11 wells, 4 showed *multiple zones of water production*, respectively, 2, 3, 4 and 9 zones.

The results of the surveys conducted indicate that the locations of water entry into the well bore can be detected when water percentages are as low as 5 to 10 pct, and

they can be detected with much greater ease with higher water percentages.

It is not the intention of the authors of this paper to suggest that all wells making small volumes of water should be worked over to eliminate that water production. Quite often the shutting off of water may shut off some oil production with it. It is, however, believed that operators can more intelligently plan workover and repair jobs on their wells if they have an accurate knowledge as to the points of entry of water within the well. In many instances such information, as demonstrated in this group of wells, would make it obvious that any type of workover performed would do more damage than benefit to the well. In other wells, the results of the survey may often prevent the operator from making the mistake of setting a plug in the bottom of the well with the intention to shut off bottom water when the survey will show that the water is entering some intermediate position.

General

As to cost of operations under this process, it is difficult to state a firm figure at this time. While a full record has been kept of the total cost both in field time and in survey time on all of these tests, it must be remembered that the tests were carried on throughout a period in which there was continuous development and improvement of instruments and procedure.

This process is somewhat more expensive than processes now available as services to the industry. This is caused primarily by the fact that tubing must be pulled and run twice, once to lower the electrode system and a second time to recover the electrode system. However, there is considerable advantage in this step since it permits tests to be conducted for several hours of fluid withdrawal from the pay section while the less expensive methods permit only a relatively few barrels of fluid to be brought into the well. Considerable thought has been given to methods of simplifying the process in order to reduce the time required for a survey and so reduce the cost. It is contemplated at the present time to design an electrode assembly that can be run in the annulus between tubing and casing. In order to shift the electrode assembly to test additional sections of the bore hole, it will not be necessary to move rods or tubing but simply to shift the position of the electrode system by raising or lowering the cable. It will be necessary, however, even with the annulus-type instruments to pull tubing twice during this process. The reason for this is that in order to determine accurately the tops of the water zones, it is necessary to pump from as close to the bottom as possible. Many wells are set up with tubing resting on a gas anchor or equivalent which makes it impossible to lower the pump inlet without first pulling tubing.

In all types of well services there are generally two types of charges, those covering field expenses and those covering the service itself. In general, surveys of this sort cost considerably more than is generally evident from the charge for the service alone. The total cost for this water survey now run approximately twice that of the type of service now available, although it is anticipated that this cost can be reduced. Even at the present cost, it is felt that the steps required to make this method more precise in its determinations will in the long run reduce the overall cost of many workovers.

Benefits to be derived from the use of the survey include not only intangible information which will assist materially in the chance of obtaining a perfect plugback operation but, in some cases, particularly those similar to wells No. 3 and No. 11 in Table 1, this survey will indicate multiple zones of water production which form such a complicated pattern that shutoff would not be attempted at all and the resulting cost of one or more "blind" workover operations would be saved.

TABLE 1—*Summary of Results of Water Entry Surveys Made during Field Trials February* 1946 *to February* 1947

Well No.	Field	State	Top of Pay, Ft	Total Depth, Ft	Production at Time of Survey, Bbl. per Day		Indicated Water Entry, Ft	Workover Performed	Oil	Water	Remarks
					Oil	Water					
1	Fish	Oklahoma	4,164	4,177	8	369 (98 %)	4,169–4,177	None contemplated	No change		Survey of this well made primarily to check field worthiness of survey equipment.
2	Sasakwa Townsite	Oklahoma	4,044	4,057	8	330 (98 %)	4,053–4,057	None contemplated	No change		Survey of this well made primarily to check field worthiness of survey equipment.
3	Midland Farms	Texas	4,705	4,820	101	10 (9 %)	4,783–4,788 4,793–4,803	None	No change		A plug-back sufficient to shut off water production would shut off some of best oil pay.
4	Midland Farms	Texas	4,675	4,813	104	13 (11 %)	4,803–4,813	Plugged back 4,813 to 4,798 ft	No change		Plug-back unsuccessful. Additional work not yet performed.
5	Fullerton	Texas	6,775	7,187	112	25 (18 %)	7,035–7,043 7,055–7,063 7,086–7,094 7,122–7,126	Plugged back 7,187 to 7,078 ft	28	17 (38 %)	Two upper water zones were not plugged off initially because of uncertainty of actual quantity of water they produced. Additional workover performed as shown below.
								Plugged back 7,078 to 6,988 ft and reacidized 6,775–6,988 ft	193	0 (0 %)	After additional plug-back and reacidization, well flowed at rate of 193 bbl per day on ¼ in. choke.
6	Iatan-E. Howard	Texas	2,285	2,642	9	30 (77 %)	2,600–2,612	Plugged back 2,642 to 2,583 ft	No change		Excess fill-up of plug-back material during workover indicated contamination and probable faulty job. Re-ran survey.
	Iatan-E. Howard (Second Survey)	Texas		2,583 P.B.	9	30 (77 %)	Plug leaking	Drilled out plug to 2,603 ft and plugged back 2,603 to 2,578 ft	9	6 (40 %)	First plug-back made with cement and plastic was entirely unsatisfactory. Second plug-back with lead wool was partially satisfactory.
7	Iatan-E. Howard	Texas	2,440	2,601 P.B.	12	125 (91 %)	2,585–2,601	Plugged back 2,601 to 2,560 ft	18	2 (10 %)	Plug-back was successful. Present water from casing seat. See subsequent survey.
	Iatan-E. Howard (Second Survey)	Texas		2,560 P.B.	18	2 (10 %)	2,213–2,217	None	No change		Water entry probably at casing seat at 2,215 ft. Since amount of water production is small, no additional workover contemplated.
8	North Cowden	Texas	4,680	4,716 P.B.	15	10 (40 %)	Plug leaking	Plugged back 4,716 to 4,699 ft	6	0 (0 %)	Plug-back successful. Now preparing to reacidize to increase oil production.

TABLE 1—*Continued*

Well No.	Field	State	Top of Pay, Ft	Total Depth, Ft	Production at Time of Survey, Bbl. per Day		Indicated Water Entry, Ft	Workover Performed	Oil	Water	Remarks
					Oil	Water					
9	Fullerton	Texas	8,527	8,558	26	20 (44 %)	8,538–8,546	None	See remarks		Prior to survey, water source was suspected either at casing seat or at bottom. Survey showed water entry to be an intermediate zone at about middle of open section. On extended pumping test water source exhausted.
10	West Lovington	New Mexico	4,675	5,120	69	28 (29 %)	4,663–4,682 4,706–4,718 4,726–4,754 4,781–4,785 4,899–4,903 4,994–5,002 5,013–5,025 5,033–5,037 5,051–5,055 Small csg. leak above 4,651	None	No change		Workover to shut off water production not feasible since water production was about evenly distributed between nine intermediate zones and a small casing leak. Prevented normal workover and probably would have assumed bottom water.
11	Hobbs	New Mexico	4,115	4,256	22	48 (69 %)	4,218–4,226 4,238–4,246 4,250–4,256	Plugged back 4,256 to 4,212 ft	19	48 (72 %)	Plug-back unsuccessful. Additional work not yet performed.

Future Plans and Conclusions

The results of the test program summarized in Table 1 indicate that the method of water-entry location described in this paper has demonstrated that it can accurately and positively locate the zones of water entry in oil wells. Wells in which the water percentage is as low as 10 pct and less can be surveyed by this process. While work to date has been carried on entirely in pumping wells, there appears to be no important reason why it cannot be adapted to flowing wells and steps are being taken at the present time to design the proper equipment in order to make this possible. Another step in the future program is to adapt the instrumentation to annulus operations which may permit some speeding up of the testing process. Future work also contemplates adapting the principles of this method to the detection of points of entry of oil and gas as well as water, since the object of this program has been, from the start, the complete determination of the character, flow rates and points of entry of oil, water and gas.

Acknowledgment

This paper is based upon work carried on at the research laboratory and in the field by personnel of the Research and Producing Departments. The contributions of Messrs. J. D. Eisler, H. M. Lang, J. A. Slicker and others are gratefully acknowledged.

Well Flowmeter for Logging Producing Ability of Gas Sands

By R. P. Vincent,* R. M. Leibrock,* Junior Member AIME, and C. W. Ziemer†

(New York Meeting, March 1947)

Abstract

The Stanolind flowmeter, which employs a hot-wire anemometer connected in a Wheatstone bridge circuit, has proved useful for determining the relative productive ability of individual sand members of gas wells. The operation of this instrument in measuring gas velocities in the well bore above each producing member has provided both a direct and accurate means of analyzing reservoir performance.

Results of tests conducted with the well flowmeter in the Hugoton gas field of western Kansas have indicated some rather unusual production characteristics. In two cases it was found that all or the greater part of the total gas produced was coming from one section in wells where four "pay" sections had been perforated individually. These actual measurements contradict in many instances the indications of data obtained from electric logs and from core analysis; the fact that these latter sources often give incorrect results, demonstrates the necessity of a method, such as is provided by the well flowmeter, for accurately determining the amount of gas coming from each producing member.

Introduction

In any gas well where a number of pay sections have been perforated individually and are producing to a common outlet, the question arises as to the relative amounts of gas being passed through each set of perforations. In the past it has been the policy to depend on core analysis to estimate relative productivities, or, where the sections were not cored, to obtain some idea of production characteristics from electric-log studies. The weaknesses in these methods are readily apparent and indicate the need for more reliable means of measuring gas flow from each zone. The Stanolind flowmeter* was developed for this purpose.

Preliminary tests were made with the instrument in the Katy gas field near Houston; however, the bulk of the routine work with the well flowmeter has been confined to the Hugoton gas field in western Kansas, where results obtained have been encouraging.

A description of the instrument, the field technique employed in testing, and a few of the results obtained in the Hugoton area are discussed in this paper.

Description of Instrument

The well flowmeter is 1¾ in. od and 7 ft long; it is entirely self-contained, can be run through tubing as small as 2 in. id in wells with high pressure (4500 psi) and temperature (210°F) and is lowered on a wire line commonly used for other instruments of the bottom-hole type at falling rates up to 500 ft per minute. It will detect gas flow as low as 10 ft per minute linear velocity, and yet withstand and record velocities of 1000 ft per minute without damage to the detecting element. Killing the well is not required nor desirable for running a production profile when using the instrument, and it is necessary to stop flow for only a short time.

The detecting element of the instrument is a hot-wire anemometer connected in a

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* Patent pending.

Wheatstone bridge circuit for accurate measurement of the resistance change of the hot wire as it is cooled by flowing fluids. In order to compensate for tempera-

FIG 1—FLOW ELEMENT.

ture variations of the fluid, a second element of the Wheatstone bridge is placed in the flow stream; by proper ratio in resistance of this element and the hot wire, satisfactory compensation is obtained for the small temperature changes ordinarily encountered in a few hundred feet of well depth. The flow-detecting legs of the

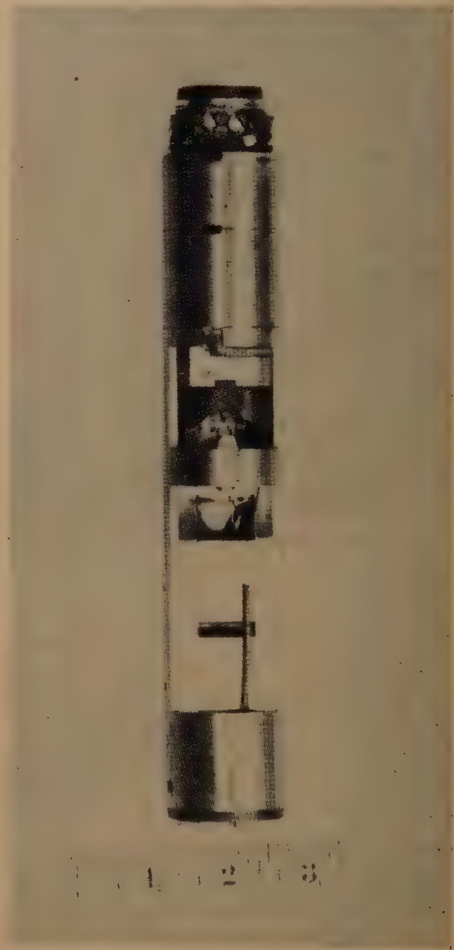


FIG 2—MOTOR-METER ASSEMBLY.

bridge are made of platinum and the other two legs of the bridge circuit are made of wire having a low-temperature coefficient of resistivity. Fig 1 shows the flow detecting and the temperature compensating elements of the Wheatstone bridge, together with a part of the device used to seal against pressure and insulate the electrical leads into the instrument case.

In order to record the balance point of

the Wheatstone bridge as it varies with the resistance of the hot wire, an electric motor powered by four flashlight batteries rotates a potentiometer through a suitable

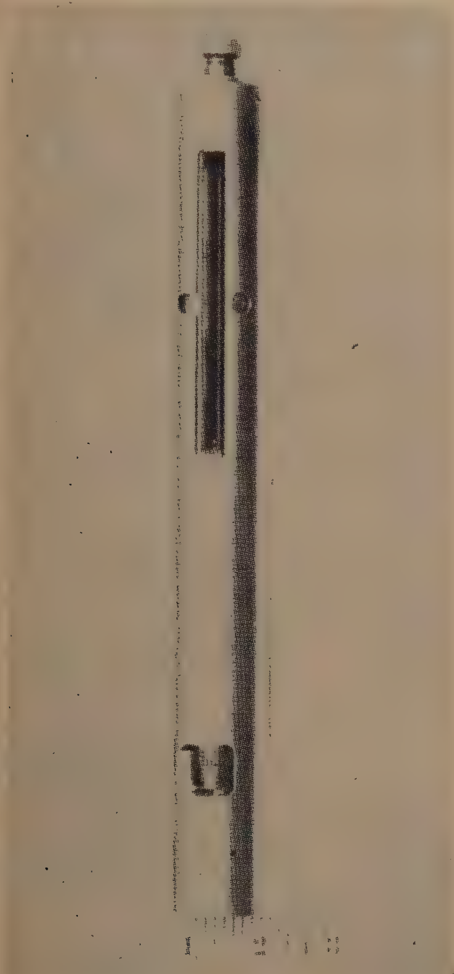


FIG 3—CHART CASE.

gear reduction, one revolution per minute. The potentiometer is connected in the bridge circuit in such a manner that it swings an indicating microammeter through the balance or null point. The motor-meter assembly, shown in Fig 2, contains the microammeter, the rotating potentiometer and the motor and gear assembly. A tapper driven by the electric motor momentarily clamps the meter hand 68 times during one revolution of the potentiometer. At the balance point the meter hand, when clamped, completes a circuit to an electro-

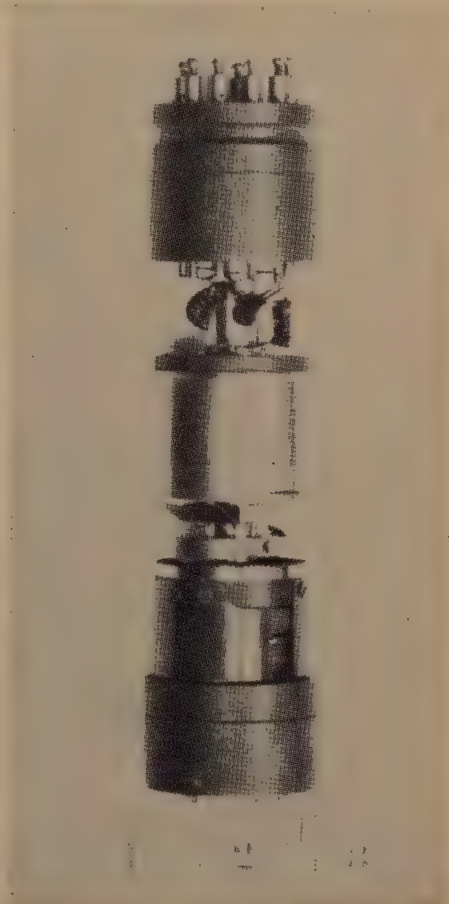


FIG 4—BALANCING POTENTIOMETER.

magnetically operated stylus which is synchronized with the rotating arm of the potentiometer. Thus, when the stylus is energized it marks a chart showing the position of the potentiometer arm when the Wheatstone bridge is in balance and thus recording change in resistance of the hot wire, which is correlated with flow rate of the fluid. One small electric motor drives the rotating potentiometer, the meter-hand tapper, and a chart carriage. The chart

case, shown in Fig 3, moves vertically with time. Correlation is made between time and depth based on records made at the surface during the test.

A means of adjusting the values of the bridge arms is provided by a balancing potentiometer shown in Fig 4. This adjustment is necessary to take care of variable temperatures and pressures existing in different wells so that maximum flow encountered in the well bore will print at the proper interval on the chart. The two arms of the bridge having a low-temperature coefficient of resistivity, together with the lower battery plug, are also part of the assembly shown in Fig 4.

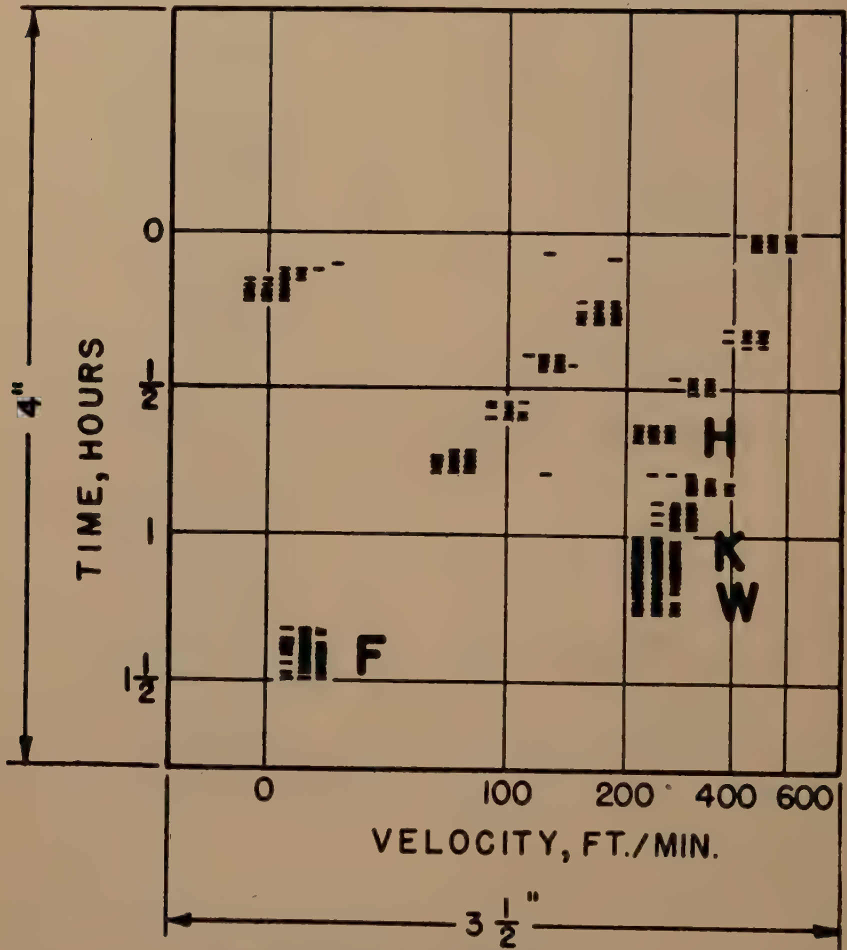


Fig 5—Well *A*, flow-recorder chart.

Field Technique

As previously mentioned, the well flowmeter is entirely self-contained and is run into the well on a solid steel wire line. It is lowered to a position just above the upper set of perforations and at least four different flow rates are obtained with the instrument, from which a calibration curve for that well is plotted. In the Hugoton field the necessary flow rates are obtained by inserting appropriate chokes in the outlet at the

wellhead. When calibration information has been recorded the instrument is then lowered to a position just above the next producing zone for a suitable period of time. This procedure is repeated on down the well bore until velocities have been determined above each producing member.

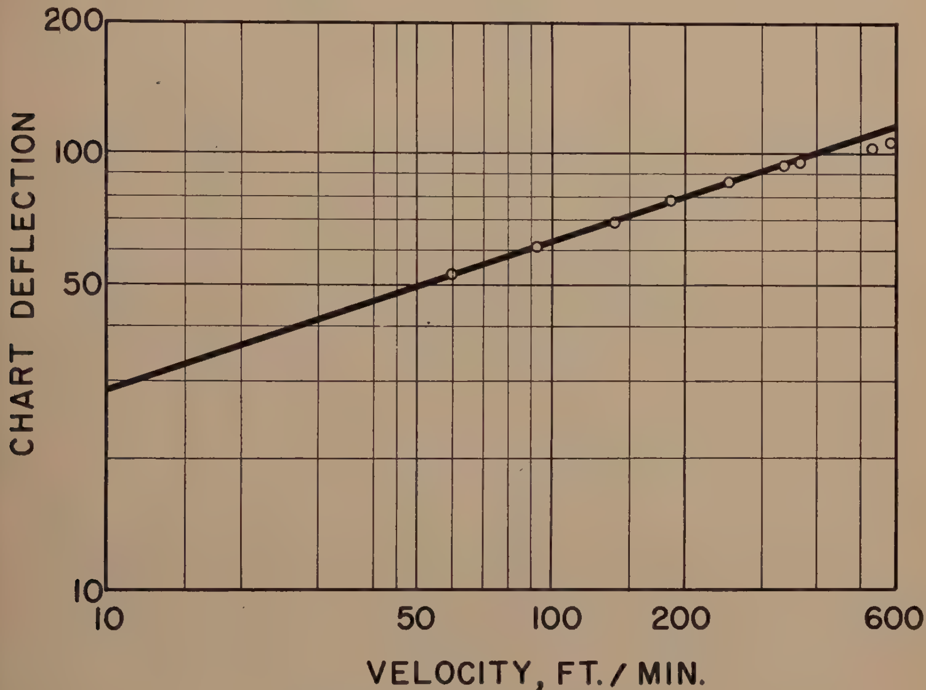


FIG 6—WELL *A*, CALIBRATION CURVE.

A typical flowmeter chart is shown in Fig 5. Due to the width of the meter hand, the electromagnetically operated stylus is energized more than just once at the balance point of the bridge; this causes the series of dots at each calibration point. In reading the chart deflection should be measured to the center of the group of dots.

Markings made on the chart while going into the hole were deleted from Fig 5. First stop, which also is the first recording with the flow-meter, was at 2430 ft which is noted as a test point for well *A* in Fig 7. At this stop at zero hours on the flowmeter chart for well *A* are a series of dots which were recorded at 593 ft/min gas velocity; the next recording was at zero gas velocity when the well was shut in. Continuing downward on the chart, other recordings were made in respective order at 187, 532, 138, 337, 93, 253, 60, 368, and 330 ft/min. The 253 ft/min velocity is marked with an *H* and is the total velocity from all members later used to determine individual members productivity.

After recording the 330 ft/min velocity, the flow rate was then adjusted to give 253 ft/min and at the same time the flowmeter was lowered to 2487 ft. The velocity recorded at 2487 ft is noted with a *K* and measures gas flowing from the Krider, Winfield, and Ft. Riley zones. Without changing the total flow rate from the well the flowmeter was lowered to 2533 ft; the record made at this depth is marked *W*. The flow rate recorded at 2590 ft, the next stop for the flowmeter, is marked *F* and is

the gas which the Ft. Riley alone produces. The chart indicates that no change in gas velocity occurred in the casing until the flowmeter was lowered below the Winfield which means that the two upper zones were not producing.

In order to estimate the percentage of gas being produced by the Ft. Riley, the calibration data are extrapolated. The

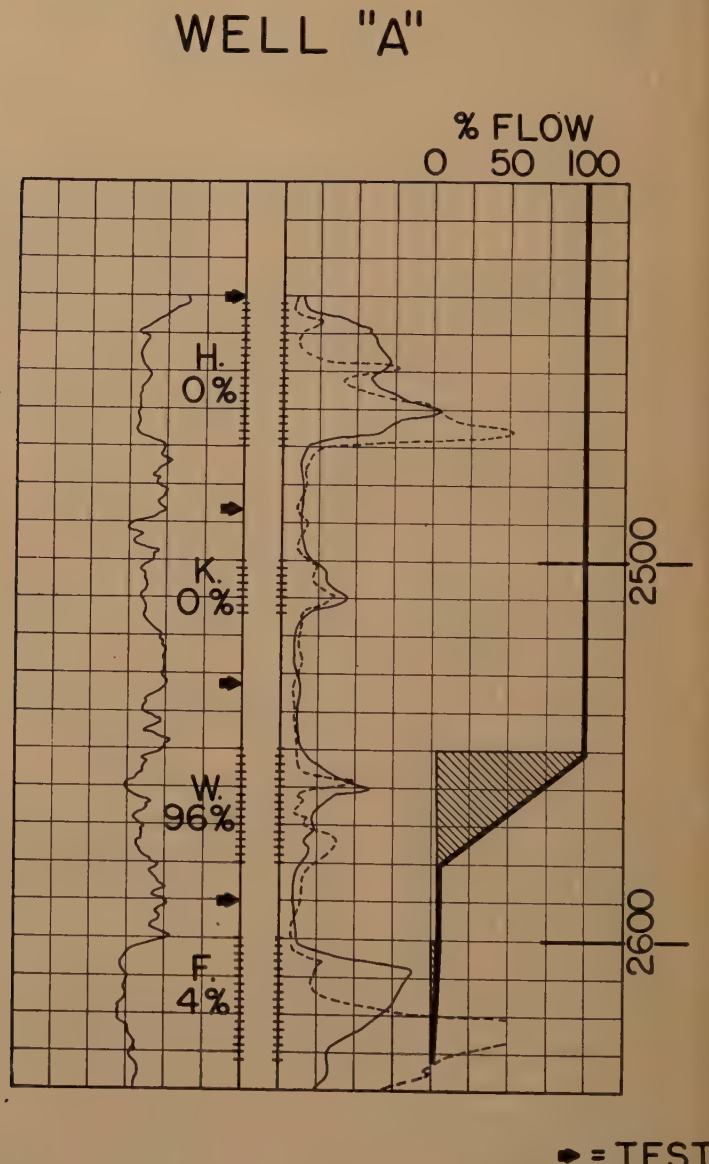
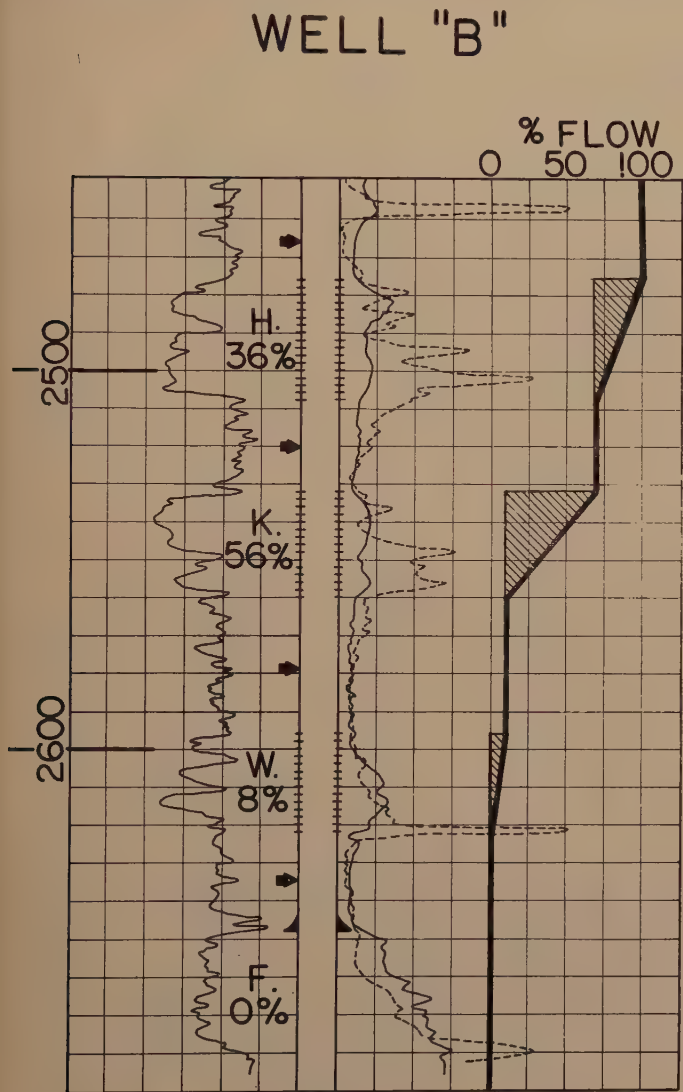


FIG 7—WELLS *A* AND

calibration points are plotted on a log-log graph, as shown by Fig 6 with the ordinate as an arbitrary scale of linear measure-

ment of chart deflections and the abscissa in ft/min. Deflection from the zero or base line of the flowmeter chart in this particular instance was measured in 1/32 in. and the values adjusted by adding a constant until the points fell in a straight line.



POINT

B, ELECTRIC LOG.

Deflection for flow from the Ft. Riley measures 6 units from the base line which added to 23, the constant necessary to straighten the calibration line, gives 29. From Fig 6 a chart deflection of 29 indicates a flow rate of 10 ft/min which is

approximately 4 pct of the velocity recorded at 2430 ft. Thus in well *A* the Winfield produces 96 pct and the Ft. Riley 4 pct of the total gas.

In making well flowmeter tests in the Hugoton field, the policy has been to obtain calibration data for each well tested; however, it may be stated, from limited information now available, indications are that for wells having approximately the same shut-in bottom-hole pressure the slope of the calibration curves will be identical.

Where dry gas is produced, as is the case in the Hugoton field, the need for considering the effects of two-phase flow is eliminated. Actually, knowledge is limited with regard to instrument behavior in wells where two-phase flow is encountered; however, results of laboratory tests indicate that the well flowmeter will measure accurately the cooling effect of two-phase flow when the liquid phase exists as finely divided mist or fog.

The length of time required to complete a test will vary from field to field. In the Hugoton field the actual time consumed in rigging up, running in and out of the hole and recording flow, is approximately five hours.

Results of Field Tests

Tests with the well flowmeter have been completed on a number of wells in the Hugoton field; however, rather than attempt a generalized discussion of all tests, it is believed desirable to consider only a few key wells.

Well A

A test was made on well *A* with stops above each producing zone in the manner previously described. Test points are indicated by arrows on Fig 7. During the test the well was produced through a ¼-in. choke at the rate of 1672 Mcf/24 hr with a wellhead pressure of 435 psi. Relative productivities from the four zones are indicated below as percentage of total flow.

Table 1—*Relative Productivities from the Four Zones*

Member	Percentage of Total Flow
Herington	0
Krider	0
Winfield	96
Ft. Riley	4

From the electric log of Fig 7, it will be noted that the porosity of both the Herington and Ft. Riley members apparently are well developed, whereas porosity in the Winfield zone appears not so good, with a rather light indication of gas. Each sand in this well had been selectively acidized, with a tubing and packer arrangement. It might be mentioned that after completion of the flowmeter test and prior to reacidizing the Herington section, a bridge plug was set just below this member and gas flow was shut off completely, thus substantiating the accuracy of the flowmeter indication.

A second test was made in well *A* to determine the effects of a two-hour blowdown on the production characteristics of the four sand members. For this test the largest available choke (⅜-in.) was selected. After the well had been blown for the two-hour period through the casing it was shut in for the few minutes required to place the instrument in the lubricator. The flowing wellhead pressure at the beginning of the test was 325 psi, a reduction of 110 psi from the previous test. At the conclusion of the testing period the pressure had built up to 352 psi at a rate of 1 lb per minute. The average rate of flow during the period was approximately 3000 Mcf per day. Results again failed to indicate any gas flow from either the Herington or Krider members.

Well B

The results of tests on well *B* are in Table 2.

The electric log shown in Fig 7 gave a

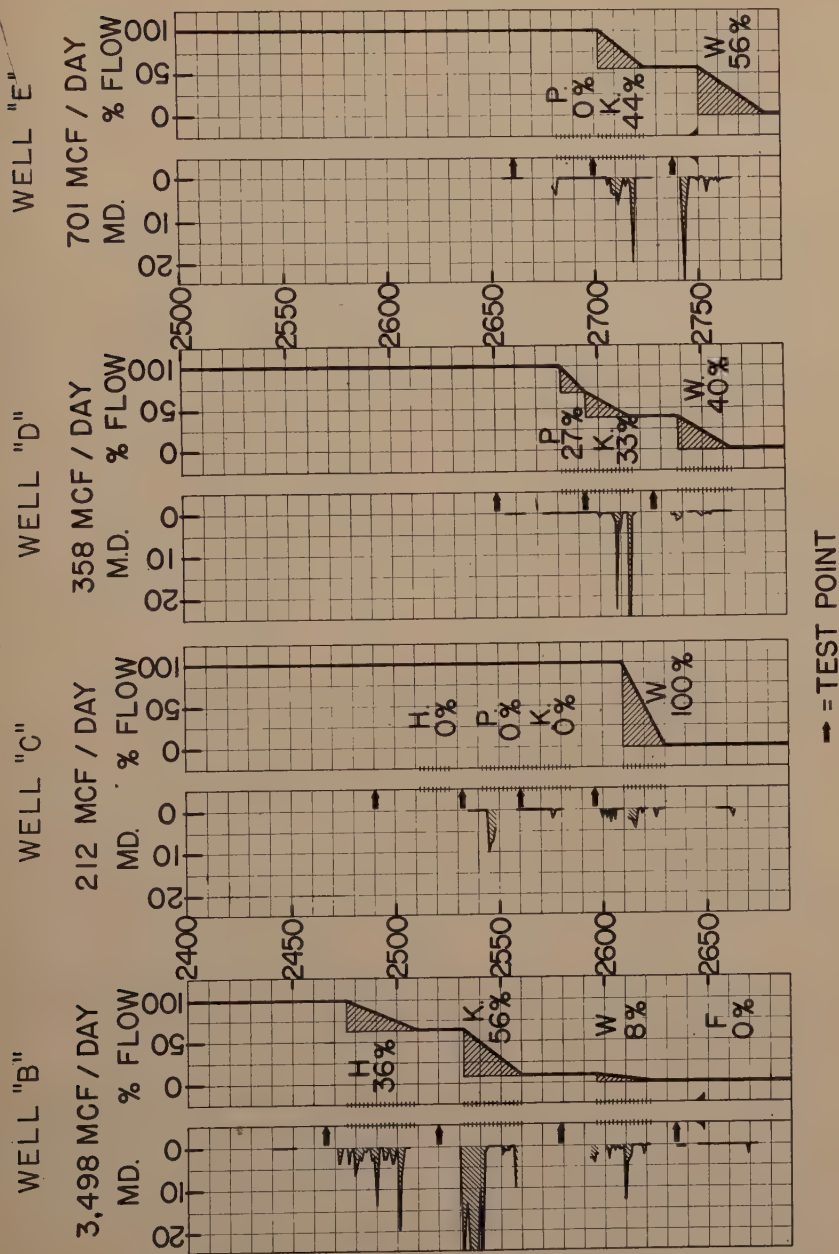


FIG 8—CORE DATA.

TABLE 2—*Results of Tests on Well B*

Member	Percentage of Total Flow	Millidarcy Ft	Percentage Millidarcy Ft
Herington......	36	90	12
Ft. Riley.......	0	0	0
Krider.........	56	634	83
Winfield........	8	39	5

fairly accurate indication of expected production from all except the lowest sand. Well *B* was one of the few wells tested in which the core data gave even a qualitative index of actual production as shown by Fig 8.

Well C

Well *C* has been selected for discussion, since the well flowmeter indicated all of the gas to be coming from the lower zone as indicated in Table 3.

TABLE 3—*Results of Tests on Well C*

Member	Percentage of Total Flow	Millidarcy Ft	Percentage Millidarcy Ft
Herington......	0	0	0
Paddock........	0	13	45
Krider.........	0	1	3
Winfield........	100	15	52

The electric log on the well indicated the porosity of both the Krider and Winfield sections to be well developed; however, core data indicated fair permeability only in the upper Paddock and Winfield members, as will be seen from Fig 8.

Well D

In well *D* sizable percentages of gas were being produced by each of the three perforated zones. Results of the well flowmeter tests, together with average permeability values for the producing members, are in Table 4.

TABLE 4—*Results of Tests on Well D*

Member	Percentage of Total Flow	Millidarcy Ft	Percentage Millidarcy Ft
Paddock........	27	0	0
Krider.........	33	32	89
Winfield........	40	4	11

It is interesting to note that 27 pct of the gas is coming from the Paddock member, which, according to core analysis, lacks permeability. In addition, there is apparently no relationship between determined permeability values and production from the two lower zones.

Well E

Well flowmeter test results on Well *E* indicated the percentages in Table 5.

TABLE 5—*Results of Tests on Well E*

Member	Percentage of Total Flow	Millidarcy Ft	Percentage Millidarcy Ft
Paddock........	0	0	0
Krider.........	44	49	93
Winfield........	56	4	7

Well *E*, although in the same section of the field as well *D*, showed no gas flow from the Paddock, where core analysis indicates lack of permeability. Here again, however, there seems to be no definite relation between the relative percentages of gas flow from the lower two zones, and the millidarcy-feet data. Graphical results of tests on wells *D* and *E* are indicated by Fig 8.

ACKNOWLEDGMENT

The authors are grateful to the management of Stanolind Oil and Gas Company for permission to present this paper, and desire to recognize the assistance given them by Messrs. J. B. Clark and Henry Schaefer in its preparation.

Significance of World Petroleum Production Trends

By Warren L. Baker,* Member AIME and L. J. Logan*

(New York Meeting, March 1947)

Abstract

By 1950 or soon thereafter facilities will be available in foreign countries for the production, transportation, and refining of about 4,305,000 bbl per day of crude oil—a volume not far short of current United States output. This is indicated by announced plans for foreign expansion, some of the work being already under way. The projected potential production is about 1,500,000 bbl per day or 50 pct above the record-setting foreign production of 2,810,000 bbl daily in 1946. The scheduled new foreign facilities are equivalent to almost one third of the present facilities of the United States.

Fears that so much additional foreign oil may flood world markets and disrupt the domestic industry of the United States are not justified. The projected foreign expansion apparently has been planned on a sound business basis, with careful consideration of the world's actual need for all the projected additional production. Materially increased world demand for petroleum promises to absorb the increased supplies without ill effect upon the domestic industry. Even by applying conservative estimates of both foreign and domestic demand, it is indicated that world requirements can absorb the projected larger foreign output and still permit continued increase in United States production. World demand would have to increase only 5.7 pct per year in the 1947 to 1950 period to absorb the prospective supply. Such an increase may be conservatively projected, in view of past and current trends.

Introduction

Recent announcements of plans for expanding petroleum facilities in the Middle East and Venezuela foreshadow an unusually sharp increase in foreign production in the immediate future. Therefore, the next few years will bring far-reaching changes in world petroleum affairs, with foreign petroleum production and other activities assuming much greater importance than formerly.

Tabulation of figures on development already under way or planned indicates that in the next several years facilities will be available for producing, transporting and refining twice the prewar production of foreign fields and about 50 pct or nearly 1,500,000 bbl a day above their record-level output of 1946.

To say that foreign fields may be producing such an enlarged quantity by 1950 is, of course, a statement of great significance to everyone connected with the oil industry and especially to those of the American petroleum industry. A production of 1,500,000 bbl daily is equal to the combined yield of the states of Oklahoma, Kansas, Illinois, Louisiana, Arkansas, Mississippi and New Mexico. This means that within the next several years foreign petroleum facilities will undergo a new expansion equivalent to one third of the present facilities of the United States.

To think of such an expansion in foreign production is to raise at this meeting the question of what this prospective foreign development means for the United States, the American petroleum industry in general, and the American engineer and technologist in particular. It is only logical to question whether or

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not so much additional oil can be absorbed by world markets; whether foreign oil is a threat to domestic producers, and how American engineers will be affected by the increased importance of foreign fields.

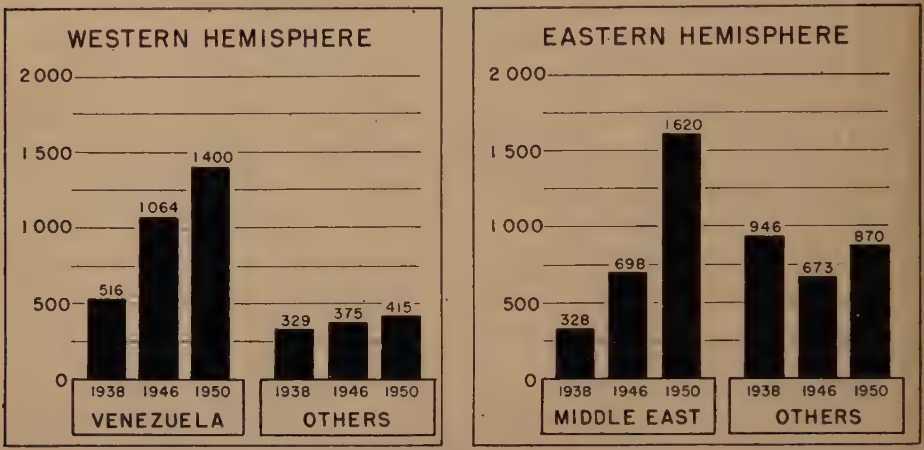

FIG 1—PAST, CURRENT AND PROJECTED PRODUCTION OF CRUDE OIL OUTSIDE UNITED STATES. All figures in thousands of barrels daily.

While it is clear that the large foreign expansion actually will occur, being definitely planned and partially under way, the answers to the above questions likewise are rather clear; and contrary to the fears held by many, the answers are generally reassuring. Projected foreign expansion apparently has been planned with careful consideration of the world's actual need for additional production. Rapidly expanding world demand for petroleum promises to absorb the larger supplies which are to be made available, without ill effect upon the domestic industry. Even by using conservative estimates, it is indicated that world demand can absorb a moderate increase in United States production in addition to all the projected gain in foreign output.

The foreign expansion of the petroleum industry holds favorable implications for American engineers and technologists, confronting them with broader horizons and increased responsibilities both at home and abroad.

FOREIGN EXPANSION PROGRAMS

The prospects of sharply increased foreign crude oil production by 1950 are based especially on expansion plans for the Middle East and Venezuela, although some expansion is indicated also for the Far East and other regions.

The past, current, and projected production of crude oil outside the United States is illustrated in Fig 1.

Venezuela, which doubled its output in the eight years from 1938 to 1946, produced an average of 1,064,000 bbl daily in 1946. At the end of 1946, this country was producing approximately 1,100,000 bbl daily, and output will rise further to 1,400,000 bbl daily in 1950 if existing and presently planned new facilities are fully used at that time. A new 300,000-barrel per day pipe line, which will connect the prolific Lake Maracaibo fields with two new refineries, is projected for western Venezuela. Other similar facilities are probable for Venezuela during the next few years, but have not been announced. Other foreign countries of the Western Hemisphere are not expected to show great expansion in the next several years, but it is quite conceivable that their production may be

increased by approximately 50,000 bbl daily by 1950.

About 60 pct of all prospective foreign expansion will be in the Middle East, which is a highly favored area of development for two important reasons: (1) the existence there of very great reserves and (2) the relative proximity of the region to Europe and other areas of large potential consumption.

Pipe line and refinery construction planned for completion in the Middle East by 1950 or soon thereafter would increase available production to 1,620,000 bbl daily, nearly 2½ times the amount produced in 1946 and five times the area's production in 1938. The prospective increase in Middle East crude production by the various countries that constitute the region is shown in Table 1.

Some of this expansion is due for completion in 1948 and most of the remainder by 1950, although some projects quite conceivably may not be completed until some time in 1950. Already under way is work on a new 16-in. Iraq pipe line from Kirkuk field to Haifa, planned to move 90,000 bbl daily. Still indefinite and not likely to be completed until 1950 or later is the similar 90,000 bbl daily capacity pipe line from Iraq fields to Tripoli. Equipment orders have been placed and preliminary work is in progress on a 30-in. pipe line from Saudi Arabian fields to the Mediterranean, world's largest oil pipe line, planned to be in operation by 1950, with capacity of 300,000 to 350,000 bbl daily. Planned but not so far along is a similar line, capable of handling 300,000 bbl daily, from Iran and Kuwait to the Mediterranean. In the meantime, the Iranian refinery at Abadan, the world's largest, will be increased in capacity by 80,000 bbl daily. In conjunction with the Middle East pipe-line construction there will be proportional refinery expansion on the eastern Mediterranean coast and in Europe.

Outside the Middle East, the Eastern Hemisphere will not experience any large individual country increases but in the aggregate the expansion may amount to over 200,000 bbl daily, mostly accounted for by Russia and the East Indies.

The stated data on prospective increases in foreign production are summarized in Table 2, as well as on Fig 1.

TABLE 1—*Crude Oil Production in Middle East*
(Thousands of Barrels Daily)

Country	1946, Average	End of 1946	1950, if Projects Completed
Iran	401	425	705
Iraq	90	90	270
Kuwait	19	45	145
Saudi Arabia	166	180	480
Bahrein	22	20	20
Total	698	760	1,620

TABLE 2—*Past, Current and Projected Production of Crude Oil Outside United States*
(Thousands of Barrels Daily)

Area	1938	1946	1950
Western Hemisphere			
Venezuela	516	1,064	1,400
Others	329	375	415
Eastern Hemisphere			
Middle East	328	698	1,620
Others (incl. Russia)	946	673	870

While foreign fields produced only 2,119,000 bbl daily in 1938, they averaged approximately 2,810,000 bbl daily in 1946 and apparently will be able to produce and feed into world markets as much as 4,305,000 bbl daily in 1950, or 1,500,000 bbl per day more than last year. These data are portrayed graphically in Fig 2 and statistically in Table 3, along with similar information on the United States and the world.

An increase of 250,000 bbl over 1946 rates has been included for the United

States. This is not intended to serve as an estimate of this country's producing ability in 1950, but is included to show further growth in United States crude production is probable despite expansion of foreign rates.

TABLE 3—*Past, Current and Projected World Crude Oil Production*
(Thousands of Barrels Daily)

Area	1938	1946	1950
World outside USA........	2,119	2,810	4,305
United States............	3,327	4,745	5,000
World Total.........	5,446	7,555	9,305

Taking into consideration these foreign prospects and assigning to the United States the previously stated moderate increase in producing ability, it is indicated that the maximum amount of world production of crude oil seeking markets in 1950 will be approximately 9,305,000 bbl daily if the large Middle East expansion is completed that soon. This would be 1,750,000 bbl a day more than average daily output for the whole year 1946, with foreign areas furnishing 1,500,000 bbl of the increase.

PRODUCTION IN RELATION TO DEMAND

Despite the magnitude of the projected expansion of foreign petroleum facilities, it is indicated, as stated before, that the potential marketable crude oil production of 1950 can be absorbed by the world markets, in view of prospective increases in consumption. This reassuring conclusion has been reached after resolving some doubts and misgivings by carefully correlating prospective production with past and prospective trends of demand for petroleum. This correlation is presented in Table 4.

In correlating production and demand, Table 4 has made allowance for natural gasoline, condensate, benzol, and other related fuels as a part of the usual supply for meeting demand.

If total supply should be in 1950 as here shown, with crude oil production at the capacity of facilities as previously projected, then world demand of 9,760,000 bbl daily for all oils would be required to absorb the production. This would be 25 pct more than the indicated demand for 1946. Such an increase would not be extraordinary. Demand increased 23 pct between the years 1932 through 1935, and grew by 27 pct between the years 1935 through 1939. Trends since the close of the war indicate the growth in world demand may be much greater. Therefore, it is significant that an increase comparable with growth during the 1930's would absorb all the projected gain in world crude-oil production. If demand should increase at a faster rate, as indicated by postwar conditions to date, then the United States undoubtedly will be required to produce larger quantities than mentioned in this paper.

An increase of 25 pct in world petroleum demand by 1950 would be equivalent to a gain of only 5.7 pct per year for each of the four years beginning with 1947, compounding the increases annually. This would compare with the annual gains which occurred regularly in the 1930's following the depression. In that period world demand for petroleum and related fuels including any prewar stock-building outside the United States, increased 4.0 pct in 1933 over 1932, 9.6 pct in 1934, 7.8 pct in 1935, 9.4 pct in 1936, 9.9 pct in 1937, declined 0.2 pct in 1938, and increased 6.1 pct in 1939.

In view of those post-depression increases and the presently indicated postwar trends, an average increase of 5.7 pct per year in world demand for the next several years appears to be a quite conservative allowance. In the year 1947, at least, it is almost certain to be exceeded, as U.S. demand likely will be up 6 to 9 pct, while foreign demand is very strong, absorbing all presently available supplies.

Besides the oils actually consumed, foreign requirements over the next several years will include substantial amounts for building up necessary stocks in consuming centers, filling new pipe lines, and filling new tanks to be built in the oil fields, along the pipe lines, at refineries, and at terminals. These requirements for stock accumulations abroad will be abnormal not only because of projected expansion of facilities but also because of the necessity of rehabilitation or replacement of facilities damaged or destroyed during the war.

Because of these abnormal foreign needs and also because foreign consumption has been increasing in normal times at somewhat higher rates than U.S. consumption, it is here assumed that in the next several years foreign demand will rise at a substantially higher rate than U.S. demand. Accordingly, the indicated increase of 5.7 pct per year in world demand through 1950 is here allocated on the basis of an average gain of 4.0 pct per year for the United States and 8.4 pct per year for foreign demand. With these increases compounded annually, U.S. demand would be 5,724,000 bbl daily in 1950, up 17 pct from 1946, and foreign demand would be 4,036,000 bbl daily in 1950, up 38 pct from 1946, to make the world total demand 9,760,000 bbl in 1950, up 25 pct from 1946, and in balance with the estimated marketable world production of 1950.

The required increase of 4.0 pct per year in U.S. consumption seems quite conservative, as gains in the 1930's amounted to 4.0 pct in 1933, 5.9 pct in

TABLE 4—*World Demand for Petroleum and Related Fuels Necessary in 1950 to Absorb Indicated Marketable Supply*
(Thousands of Barrels Daily)

Area	1938	1946	1950	Difference in 4 Years, Pct	Difference per Year, Pct
Demand:					
World total	5,707	7,816	9,760	+24.9	+5.7
United States	3,115	4,893	5,724	+17.0	+4.0
Foreign (including additions to stocks)	2,592	2,923	4,036	+38.1	+8.4
Change in U.S. Stocks	−25	+129			
Production:					
All oils, World	5,682	7,945	9,760		
United States	3,472	5,065	5,375		
Foreign	2,210	2,880	4,385		
Crude oil, World	5,446	7,555	9,305		
United States	3,327	4,745	5,000		
Foreign	2,119	2,810	4,305		
Related fuels, World	236	390	455		
United States	145	320	375		
Foreign	91	70	80		
Crude Oil Production by Principal Sources:					
Western Hemisphere	4,172	6,184	6,815		
United States	3,327	4,745	5,000		
Venezuela	516	1,064	1,400		
Others	329	375	415		
Eastern Hemisphere	1,274	1,371	2,490		
Middle East	328	698	1,620		
Russia	561	438	560		
Others	385	235	310		
U.S. Exports-Imports:					
Exports, all oils	531	412	175		
Imports, all oils	149	369	524		
Net exports	382	43			
Net imports			349		

1934, 6.9 pct in 1935, 11.0 pct in 1936, 7.0 pct in 1937, interrupted by a decrease of 2.8 pct in 1938, and a further rise of 8.2 pct in 1939. Likewise an assumed increase of 8.4 pct per year in foreign demand, when considered along with the above abnormal conditions, appears sufficiently conservative, as increases in the 1930's amounted to 4.0 pct in 1933, 15.1 pct in 1934, 9.0 pct in 1935, 7.2 pct in 1936, 14.0 pct in 1937, 3.1 pct in 1938, and 3.6 pct in 1939.

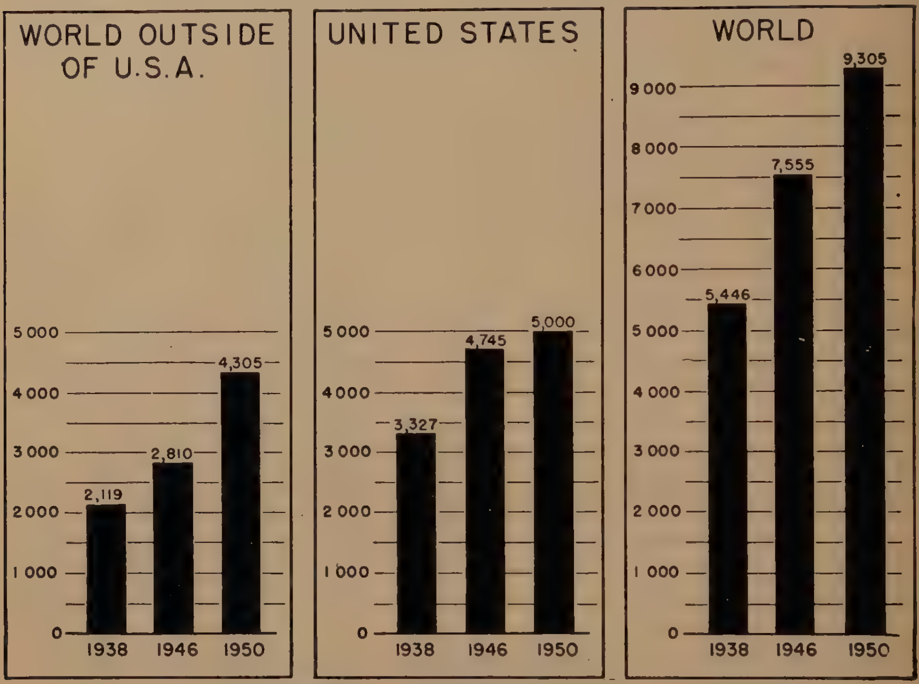

FIG 2—PAST, CURRENT AND PROJECTED WORLD CRUDE OIL PRODUCTION.
All figures in thousands of barrels daily.

Actually, U.S. demand quite conceivably may exceed the above allowance, in which event foreign demand could show less increase than allowed for, without necessitating any downward revision in the world demand needed to absorb the projected production.

U.S. EXPORTS AND IMPORTS

In connection with these figures on projected production and demand, the accompanying table has been made to include data on United States exports and imports, in order to show the indicated effect on these shipments. Almost certainly, the United States very soon will cease to be a net exporter of oil, as it has been traditionally in the past.

With U.S. production and demand as projected, this country would be producing more crude oil and more natural gasoline and related products in 1950 than in 1946, but the total domestic production would fall short of domestic consumption by 349,000 bbl daily, whereas production in 1946 permitted a net export of 43,000 bbl daily besides allowing a stock increase of 129,000 bbl daily. The deficiency of 349,000 bbl daily in domestic supply would be filled by net imports, which would be the difference between reduced exports and increased imports. This result might be shown, for example, by a decline in total exports to 175,000 bbl daily in

1950 from 412,000 daily in 1946 and an increase in total imports to 524,000 bbl daily in 1950 from 369,000 bbl per day in 1946. These results would be an extension of the actual trends of recent years, as exports averaged 531,000 bbl daily in 1938, against imports of 149,000 bbl daily, to indicate a net export of 382,000 bbl daily in that year.

It is noteworthy that while these figures call for a substantial decrease in U.S. exports, they do not require a very great increase in actual imports, which in rising from 369,000 bbl daily in 1946 to 524,000 bbl daily in 1950 would increase 155,000 bbl daily over a period of four years. If exports should be reduced even more than shown, then necessary imports would be less than indicated. While it is not conceivable that exports should decline to 20,000 bbl per day, such a decrease would leave the indicated necessary imports at the same level as in 1946.

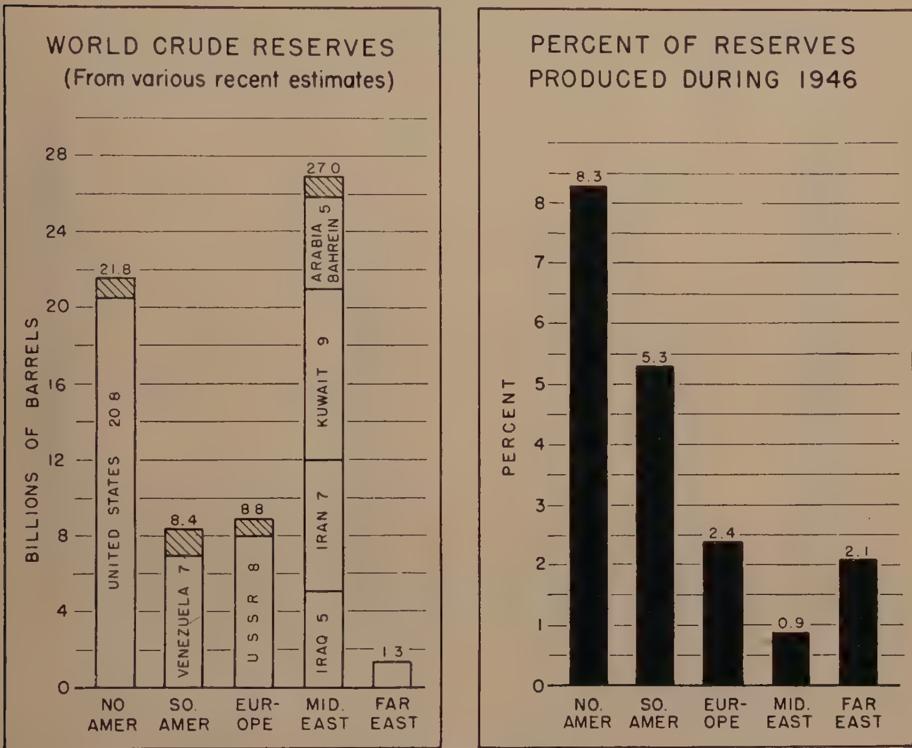

FIG 3—WORLD RESERVES.

IMPLICATIONS FOR DOMESTIC OPERATIONS

While this prospect for the future is not one calling for a shrinkage in domestic operations, it does involve a new situation in which domestic production of crude oil should not be expected to continue to increase indefinitely as the nation's already tremendous requirements further expand. Highly mechanized, the nation has been using up petroleum at such high rates in recent years that annual requirements have come to be a very heavy drain on available proved reserves, in spite of some success in extreme efforts to bolster or increase the reserves.

So great have been requirements that actual production has been for several years very close to the ability of reservoirs to give up their oil without waste. As indicated in Table 5 and Fig 3, the United States in 1946 produced the equivalent of 8.3 pct of its proved reserves, thereby making relatively a much heavier drain on its reserves than was made on any other major reserve in the world.

TABLE 5—*Rate of Annual Drain on Proved Reserves, by Continents and Major Regions*, 1946

Region	Reserves, Jan. 1, 1946 Mcf Bbl	Annual Production, 1946	
		Mcf Bbl	As Percentage of Reserves
North America	21,849,813	1,808,526	8.3
United States	20,826,813	1,731,889	8.3
Others	1,023,000	76,637	7.5
South America	8,366,000	448,295	5.3
Venezuela	7,000,000	388,200	5.5
Others	1,366,000	60,095	4.4
Europe	8,840,150	209,794	2.4
Russia	8,000,000	160,000	2.0
Others	840,150	49,794	5.9
Middle East	27,000,000	254,677	0.9
Iraq	5,000,000	32,777	0.7
Iran	7,000,000	146,500	2.1
Kuwait	9,000,000	6,900	0.1
Qatar	1,000,000		
Saudi Arabia and Bahrein Island	5,000,000	68,500	1.4
Far East	1,310,000	27,150	2.1
East Indies	1,075,000	16,000	1.5
Others	235,000	11,150	4.7

Even a 7 pct annual drain on U.S. reserves would have been above the prewar normal, and one around 6 pct would have been about normal.

The next heaviest drain on reserves in 1946 was that of 5.5 pct in Venezuela. While that was itself relatively high, it was below the U.S. prewar normal, and Venezuela has comparatively good possibilities for discovery of additional new reserves, as it has experienced only superficial development.

In contrast with these results in the Western Hemisphere, reserves in the Middle East, the East Indies, and Russia are large, yet they are being drawn upon at rates of only 1 to 2 pct per year. Those areas obviously offer exceptionally good possibilities for expansion of annual producing rates.

Even to maintain domestic reserves at present proportions and production at the present high level would require very active exploration and development. For it would be no easy task to prove up henceforth in the United States 1,750,000,000 bbl of new oil reserves per year to compensate for production of 4,750,000 bbl daily, the approximate rate for 1946. If the nation's crude oil production should be increased to as much as 5,000,000 bbl daily through accelerated discoveries and enlargement of reserves, then the maintenance of production at such a level would require the proving up of 1,825,000,000 bbl of new reserves annually. The industry actually has proved up an average of approximately 1,900,-

TABLE 6—*Producing Oil Wells and Their Daily Average Output, by Major Regions, End of* 1946

Region	Producing Oil Wells		Oil Production		Output Per Well, Bbl Daily
	Number of Wells	World Total, Pct	Bbl Daily	World Total, Pct	
United States	424,286	90.5	4,705,000	61.8	11.1
Middle East	185	0.04	760,000	10.0	4,108.1
Venezuela	4,935	1.1	1,100,000	14.5	222.9
Rest of World	39,345	8.4	1,043,000	13.7	26.5
Total World	468,751	100.0	7,608,000	100.0	16.2

000,000 bbl of new reserves annually since the end of the 1930's. But it has done so only by repeatedly setting new records in volume of wildcatting, without at any time equaling the success of the late 1930's.

In seeking to meet tremendous oil requirements while holding relatively lean domestic reserves, the United States now faces not only the physical limitations imposed by nature in the distribution of the earth's oil but also the economic limitations involved in depending more and more upon fields in advanced stages of depletion.

At the end of 1946 the United States operated 90.5 pct of the world's producing oil wells but obtained only 61.8 pct of the world's oil production, as the average daily output of 11.1 bbl per well was far below the average for the rest of the world. These figures for the United States are here compared with corresponding data for other important producing areas. (Table 6 and Fig 4.)

Only a favored few of the best wells in the United States are produced at rates as high as the general average of 223 bbl daily per well for Venezuela. In the Middle East, some wells are produced regularly at 10,000 bbl daily per well, and even the average is 4108 bbl. Venezuela and the Middle East thus account for large proportions of world production with very small proportions of the world's wells. In the remaining foreign fields average output per well is more than twice the U.S. average and 13.7 pct of world production is obtained from 8.4 pct of the wells operated.

To drill and operate so many wells, economies and efficiency are more necessary in the United States than elsewhere, and

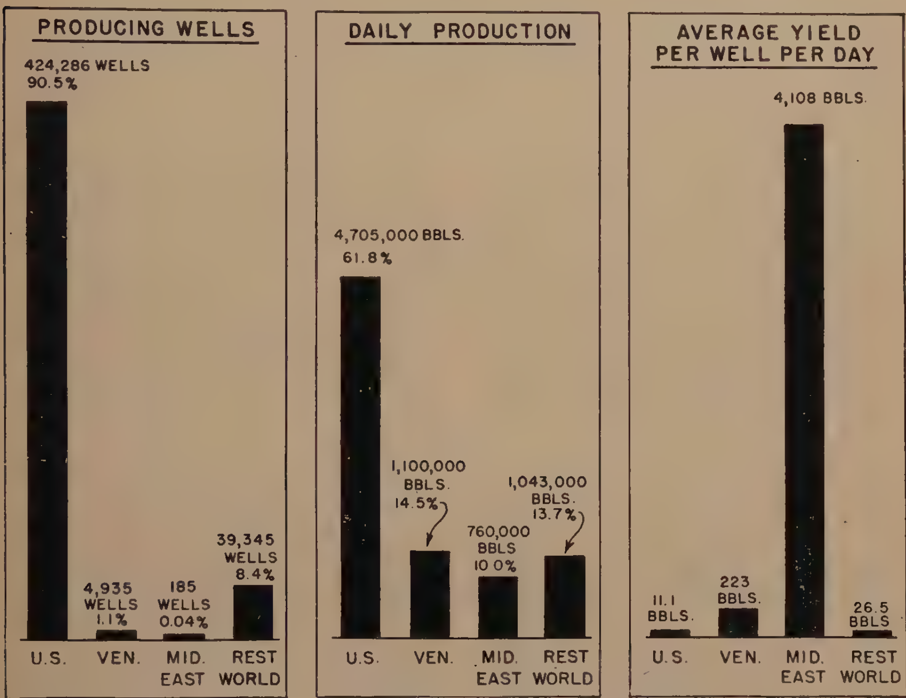

FIG 4—WORLD'S PRODUCING OIL WELLS AND YIELD, END OF 1946.

this necessity for efficiency in domestic operations is accentuated by the present expansion of foreign production.

In view of the increased difficulty of proving up new domestic reserves in recent years and the economic limitations involved in domestic operations, the only safe assumption that can be made regarding domestic production of crude oil is that it will further increase only moderately or tend to flatten out at prevailing levels, some petroleum economists having doubt that even the present production can be maintained beyond a period of several more years. However, there is general agreement that United States consumption will continue to grow.

As domestic requirements further expand, any deficiency of domestic supply would have to be met by imports; and even if domestic crude production should be as high as 5,000,000 bbl in 1950, there might be need for importing 525,000 bbl daily, estimating that exports will then average around 175,000 bbl daily.

In the light of increasing world consumption and the position of the United States industry, it is indicated that instead of being a threat to the United States, the increased foreign production of several years hence may be welcomed. Meanwhile, domestic producers will have a ready market at home for all the oil they can produce.

Implications for Engineers

Also indicated by the above discussed world developments and trends are some favorable implications for American engineers and technologists in particular. Because of the foreign expansion, the American engineer finds himself facing broader horizons, although also charged with increased responsibility. If he wishes, he may find for himself an active part in the important work which inevitably will be done abroad in coming years. His knowledge and experience will bring a premium in the foreign fields where needed. If he prefers, he can leave the foreign work to others and concentrate on the technical problems of the industry at home. Here again he will be urgently needed, more than ever before, since ever increasing efficiency of the domestic industry will be the means through which the industry can hope to hold its own in supplying the nation and in world competition.

Insofar as the United States is to continue meeting its domestic needs from domestic sources, it must increasingly "stretch" its available proved reserves by achieving greater recovery of oil from the reservoirs, prove up additional reserves by improving finding techniques and exploring new areas including the Continental Shelf, and bring into the picture synthetic liquid fuels from natural gas, shale, coal and other sources. All this means work for engineers. Insofar as the nation continues independent of foreign sources for its liquid fuels, it will do so largely through the efforts of the technologists of the industry. By the same token, if the nation turns to the foreign sources for increasing portions of its liquid fuel needs, it will be at least in part because American technology cannot make domestic resources suffice. Thus the American engineer faces a great opportunity and a great challenge, and in large measure it is he who must offer the final answer to the controversial question of whether the United States will become a large net importer of oils.

In the meantime, practical economics indicates that the nation eventually may find it expedient and desirable to meet a considerable part of its future liquid fuel requirements from crude oil produced in foreign fields. And since American oil companies and American engineers have largely pioneered oil development as now practiced, it is quite fitting that American interests and American engineers should be now taking a leading role in the present day vast expansion of foreign facilities, which will ultimately benefit the whole world as well as our own nation.

What Does Industry Have a Right to Expect of Petroleum Engineering Schools?

By P. H. Bohart,* Associate Member AIME

(New York Meeting, March 1947)

Abstract

The answer to the title question will be found by considering the ultimate influence of the petroleum engineers on industry and by considering the tools with which petroleum engineers must be equipped. Some 2000 to 3000 petroleum engineers are being absorbed by the industry yearly, indicating the magnitude of influence which they may exert on the industry.

The petroleum industry is a highly technical one and it is inevitable that management be entrusted more and more to executives with technical training. The industry, therefore, expects the petroleum engineering schools to provide a broad basic training and a social and economic orientation which goes beyond merely supplying the minimum technical qualifications necessary to discharge responsibilities for a particular job. Because of the many branches of industry, emphasis must be placed on the student's being trained in fundamentals, as well as grounded in other engineering branches, such as mechanical, civil and electrical engineering. The petroleum engineering graduate must know how to outline and organize the material for an engineering report and should be thoroughly grounded in English, both written and spoken.

Even to the end that a five-year course may be required, they should receive instructions in auxiliary cultural and social science courses, industrial relations, and public speaking. Training in the method of approach to an engineering problem is something in which industry is deeply interested. A standard of ethics, a desire to arrive at the truth, and leadership training should be stressed.

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Introduction

The basis of an answer to any question concerning the petroleum engineering schools' responsibility to the industry will be found by considering the ultimate influence of the petroleum engineers on the industry and by considering also the tools with which petroleum engineers must be equipped in order to achieve success and happiness in the role in which their training, individual talents and choice of a profession ultimately will cast them. The problem must always be considered as it relates to a large group and not as it relates to a particular individual possessing strong natural talents and destined, by virtue of them, to pursue a certain course.

The question implies that petroleum engineering schools have a responsibility, and indeed they do, not only to the industry but also to the students and even to the public. Because the responsibility is concentrated in a relatively few schools whose graduates are absorbed largely by the one industry, the responsibility is more apparent and the effect of failure to discharge the responsibility fully is more serious than the effect of similar failure on the part of schools supplying a smaller portion of the industry's intake of engineering graduates. This fact is especially true with respect to an industry such as the petroleum industry whose ratio of technical to nontechnical employees is relatively high and is increasing.

Recent Student Enrollment

The number of petroleum engineers already employed and to be employed will

throw some light on their probable future influence on the industry and on the petroleum engineering schools' responsibility to the industry. The number of students enrolled in petroleum engineering schools from 1936 to 1945, as reported by Plank,[1] and shown in Table 1.

TABLE 1—*Enrollment in Petroleum Engineering Schools*

Year	Number of Students
1936–1937	2,466
1938–1939	3,538
1940–1941	2,877
1941–1942	2,143
1944–1945	376
Nov. 5, 1945	1,083

Enrollments formerly were substantial and, although drastically reduced by the war, are increasing. One authority estimates that engineering enrollments have increased 75 pct since the 1945 to 1946 term. A Middle West petroleum engineering school anticipates that its enrollments in 1949 to 1950 will be double its 1939 enrollments. A similar increase perhaps is not expected by all petroleum engineering schools, but certainly the enrollments by 1949 will be greater than ever before and certainly the 2000 or 3000 petroleum engineers who will be absorbed by the industry each year will exert ultimately an important influence on the industry.

Engineers in Industry

The industry has employed and will continue to employ chemical, electrical, mechanical, mining, and civil engineers, and geologists in large numbers in all of its branches—production, transportation, refining and research. However, for a number of years many large petroleum operators in selecting new engineers have employed in production operations more petroleum engineers than engineers of any other type. Two companies report that 75 pct of their engineers in production operations are petroleum engineers, two report 60 pct, three report 50 pct and one reports 40 pct. Two companies report having employed in the past two years a greater portion of petroleum engineers than in previous years. These figures are not complete and are only approximate. However, they do show that the industry has been absorbing a great number of petroleum engineers and that in production operations the trend has been toward the employment of more engineers with petroleum degrees than with other degrees.

The inference should not be drawn that there is any trend toward the employment of petroleum engineers exclusively, even in production operations. The future trend in employment will depend not on the fact that an applicant's degree, by the inclusion of a word, indicates some special emphasis on petroleum but on actual experience over a period of time which will indicate the adequacy of the curricula and the quality of the undergraduate selection and training. What has been acceptable up to now may not be acceptable in the future, and this thought provokes the suggestion that since the oil industry probably will undergo profound changes and adjustments which are and will be necessary to meet changing domestic and world conditions, petroleum engineering schools would do well to equip undergraduates so that they will encounter no serious difficulty in adjusting their own perspectives and in keeping in step with changing conditions in the industry.

Figures quoted, incomplete though they be, indicate that petroleum engineers will be employed in sufficient numbers to make up an important group in the industry. Its importance will be greater than can be measured by its numbers because of the type of work in which petroleum engineers will be engaged. Inevitably, some of them will become members of the management group. As such, they will assist in forming policies and will share the responsibility of maintaining the industry in its proper place in the national economy. As engi-

[1] References are at the end of the paper.

neers, they will share the responsibility of preserving the industry's leadership in technical advances. Clearly, the schools supplying the basic training for this large segment of the industry's key personnel have assumed and will discharge a serious responsibility to the industry and even to the nation. Just as clearly, the industry has a right to expect these schools to recognize and live up to this responsibility. In the past a vigorous, progressive, sound industry has met every challenge presented either by a national crisis or by a change in the national economy which affected or was affected by its production. If in this matter a lesson has been learned, it is that a vigorous, progressive, sound industry will be required to meet future challenges.

Industry Grows More Technical

The petroleum industry is a highly technical industry. Drilling locations no longer are selected because of the resemblance of the topography and vegetation of some particular spot to the corresponding physiographical features of some place where oil was previously discovered. Locations are selected today, for the most part, only after the completion of exhaustive scientific studies. Modern drilling, production, transportation and refining practices all have been developed by scientific research and the application of engineering. Even in sales promotion, engineers and technical knowledge have their places, and the development of new markets and new products for old markets is a research problem. As almost every phase of the industry has become more technical, it was inevitable and logical for management to be entrusted more and more to executives with technical training. Plans and policies in the future will be governed by technical developments more than by any other single factor. In the next decade the success of exploration, the efficiency of both primary and secondary production methods, the ability to drill to substantially greater depths, and the development of competitive synthetic processes will determine the trend of the industry as a whole as well as the activities of the various units of the industry. It is inevitable that many of the engineers of today, and among them petroleum engineers, will be the planners and policy makers of tomorrow. Does not the industry, therefore, have the right to expect the petroleum engineering schools to provide a broad basic training and a social and economic orientation which goes beyond merely supplying the minimum technical qualifications necessary to obtain a job or discharge the responsibilities of a particular job? If our system of free private enterprise is sound—and no industry better than the petroleum industry illustrates its soundness—is it not vital that petroleum engineers understand the philosophy of this type of economy? Such a system, obviously, is necessary and it is also necessary that these students be well grounded in the history of the oil business in the United States and in foreign countries so they may understand the industry and why it has progressed in the last thirty to thirty-five years almost with the speed of an explosion. They are entitled to a clear knowledge of the environment into which they are graduating.

Fields Open to Engineers

Petroleum engineers are individuals and not machines manufactured to a given set of specifications; therefore, they will continue to exhibit a wide range of talents and combinations of talents despite all efforts, by aptitude and preference tests, to restrict the field to those best fitted for engineering careers. Although many will make production or refining engineering or scientific research their life's work, many will branch off into other kinds of work. Some will become foremen and climb the administrative ladder to higher executive positions; some will go into business for themselves—

drilling, research, producing, manufacturing, distributing, or consulting work; some will become associated with large operators and others with small operators; and some will become salesmen. Most will be doing something useful related to oil. Much will depend on the wheel of fortune and many will not realize until they have been out of college for several years for what type of work they are best fitted. It is then too late to start over and the tools with which they are equipped must suffice to a reasonable extent.

Broad Education Needed

The petroleum industry must be considered as made up of not only the producers, refiners, and marketers but also the service companies, contractors, and manufacturers of oil-field equipment, besides the many individuals who buy leases and drill wells, and the consulting engineers, geologists, and geophysicists. In designing a course of study it is impossible to anticipate the specific job requirements of each of the many branches of the industry just as it is impossible to foresee the ultimate niche into which each petroleum engineering graduate will fit himself. It seems apparent, therefore, that the emphasis must be placed on fundamentals and that the student must receive as broad a course as possible so that he will find himself reasonably well equipped wherever he may start and wherever fate and his particular talents may take him. The industry will always have openings for a relatively small number of specialists trained for highly technical work, but by far the greatest number of technically-trained personnel absorbed each year must "specialize on the job." The industry has the right to expect these people to come to it prepared in a way which will permit the greatest possible latitude and flexibility in molding them into efficient members of its complex organization. Working from a broad foundation of well-taught fundamentals, the individual can take full advantage of industry's "on-the-job specialization" and grow in the direction of his maturing tastes and talents.

The mining industry found that a large portion of its engineers should have a broad training in mechanical engineering, civil engineering, electrical engineering, chemistry, geology, and metallurgy. To a considerable extent, at least in production, the petroleum industry's requirements are not unlike those of the mining industry and it would seem that the petroleum industry also has a right to expect its petroleum engineers to be well grounded in the fundamental engineering branches.

It is not necessary that a graduate petroleum engineer know what a sucker rod is but it is very necessary that he know something about thread design and stresses, and something about iron and steel and alloys. It is not necessary for him to know how to make a material-balance computation but very necessary that he be thoroughly grounded in mathematics and physics. He should know how to outline and organize the material for an engineering report, but that is not enough. He should be thoroughly grounded in English, both written and spoken, in fact just as well grounded as in mathematics or any of the engineering subjects. Considering the great strides in science which have been made in the last twenty years, it is difficult to adequately prepare an engineer in four years and a great deal of sound argument can be advanced for a five-year course. Certainly there is little time during the standard four-year course to crowd in very many of the so-called "descriptive" courses or "courses of application" without sacrificing some of the fundamentals, particularly if there is to be included in the four-year course the necessary instruction in auxiliary cultural and social-science courses such as psychology, history, economics, and even industrial relations and public speaking. Instruction in these subjects should be included be-

cause as the importance of the engineering profession has increased and industries have become more technical, inevitably the engineers have occupied positions requiring more than technical knowledge and the industry has a right to expect its petroleum engineers to come to it prepared to fit themselves into roles which give greatest expression to their talents and personalities. By so doing they will serve the industry best.

With sufficient time at their disposal, it is easy enough for the petroleum engineering schools to provide the necessary basic training to meet any given set of what might be termed "tangible requirements," but probably it is not easy to provide the necessary background and environment to develop the philosophy, ethical standards, and the habit of using the "engineering method" which engineers should have, because these can not be given in specific three- or four-hour courses. Nevertheless, this training in the intangible requirements is something in which industry is deeply interested. The approach to an engineering problem, the engineering method, requires close and accurate observation, complete collection of facts, logical analysis, synthesis of pertinent data, and decision. It will be invaluable to them and their employers if engineers acquire in college the faculty and habit of applying this procedure—too many do not. Not every individual possesses the same natural faculty for approaching a problem in this way and it is important to try to develop it.

A standard of ethics, a desire to arrive at the truth, and a determination not to stop short of the best that can be done, to a large extent, are innate characteristics but also to some extent are a matter of attitude and mental habit. They can not be taught in special courses, but teaching them can be woven into every course. Industry and, in fact, the public have a right to expect these characteristics in professional people who by virtue of their special training are entrusted unavoidably with a large responsibility to others. The engineering profession is no exception.

The schools have a definite duty to help the students form a workable philosophy of life which includes an appreciation of the service of science to mankind and a belief in the obligation of the individual who enters a profession to exalt himself by continuing his studies and growth so that he may never cease making contributions to the advancement of science and industry. In other words, industry has the right to expect petroleum engineering schools to supply to their students inspiration and inspiring leadership. Dr. Lee Irvin Smith[2] expresses it all very succinctly by saying: "The professional man must be the whole man." He points out a lamentable truth that many professional men are "nothing more than scientific drones" who "produce no ideas" and who "haven't read a book or studied the scientific literature in years." The industry has a right to expect the petroleum engineering schools to reduce to a minimum the number of potential "drones" they graduate.

Conclusion

In attempting to answer the title question, the writer does not intend to imply a criticism of the petroleum engineering schools but rather takes this opportunity to express a profound admiration for what they have done in a brief span of years. Neither should it be inferred that he believes that any of the requirements has been overlooked. The purpose is to emphasize that all of these requirements are of serious moment to an industry which is relying on the petroleum engineering schools to an important degree and which has a large and serious responsibility to the public and to the nation.

Acknowledgments

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2. Lee Irvin Smith: Mutual Responsibilities of Scientists and Industry. *Chem. Eng. News* (Dec. 25, 1946) **24**, No. 24, 3342.

DISCUSSION

H. G. Botset*—The question which Mr. Bohart has raised, and in the writer's opinion, very adequately answered, presents a real challenge to our petroleum engineering schools. The petroleum industry rightfully has a strong interest in the educational program which is supposed to be designed to prepare the oncoming generation of engineers properly to fulfill the responsibilities which will ultimately be theirs. The increasing complexities of these responsibilities makes the problem of adequate preparation ever more difficult to solve.

The great broad foundation upon which an adequate industrial petroleum engineering staff rests is the quality of the college undergraduate curriculum, for the majority of petroleum engineers have only the B.S. degree. Furthermore, if the undergraduate preparation has been inadequate, the quality of the candidates for graduate training will inevitably be impaired. It seems to the writer that there has been lately an ever increasing attention to, and emphasis on, the importance of graduate programs, for which extensive sums of money for equipment and fellowships have been contributed by oil companies, while there has been much less concern with improving the foundation—undergraduate education. That Mr. Bohart apparently does appreciate the importance of this is apparent from the second sentence of his paper.

The last three sentences preceding Mr. Bohart's conclusions point to a very real problem in petroleum education and one which the industry might aid materially in solving. It is the problem of quality of teaching staff. If we are to prepare petroleum engineers properly on the undergraduate level, the teaching staff must be of very high quality, actually (contrary to the apparent attitude of many universities) at least as high quality as for direction of graduate work. Mere knowledge of formulas, equations and terminology is not sufficient qualification for a teaching position. The "whole man" must have, in addition to adequate industrial experience, a broad general cultural background, a wide knowledge of and enthusiasm for the whole petroleum field, as well as a liking for and understanding of men and students. These are very special qualifications and if a university should find a man who has them, he will doubtless already be receiving much more salary than the university can offer.

A recent editorial (the Dec. 29th issue of *Chemical & Engineering News*) states "Unfortunately salaries paid by Government and by our colleges and universities generally are lower than salaries offered by private industry" and further ". . . but badly needed increases across the board for the teaching profession are contingent largely on finding additional sources of revenue." If the industry really wants to improve the quality of education offered petroleum engineers, it is suggested that some means be devised whereby, in addition to industry's contributions to graduate fellowships and equipment (and these are very necessary) provisions of some sort should be made to help universities pay the salaries needed to attract the proper type of engineer into educational work. The net return to the industry would undoubtedly be large.

P. H. Bohart (author's reply)—The original paper under discussion emphasized the importance of a broad, flexible education for undergraduate engineers. In this connection Mr. Botset's discussion outlines the need for improved quality in teaching staffs and the necessity for higher salaries in order to attract men with "adequate industrial experience, a

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broad general background, a wide knowledge of and enthusiasm for the whole petroleum field, as well as a liking for and understanding of men and students." Mr. Botset further suggests that "if the industry really wants to improve the quality of education offered petroleum engineers, it is suggested that some means be devised whereby . . . provisions of some sort should be made to help pay the salaries needed to attract the proper type of engineer into education work."

It seems evident that, generally speaking, salaries of teachers in schools, colleges and universities have not kept pace with either the increased cost of living or the demand for improved standards of instruction and, certainly, this question deserves more consideration by educators and more recognition from the public at large. The paper under discussion was largely confined to a discussion of the end rather than the means and, for that matter, the principal point, as far as academic education is concerned, is the necessity for greater stress on fundamentals than on specialized training. There is no question but that improved quality of instruction is important and should be the goal of every college. This may necessitate higher salaries as well as other requirements, but the first objective should be to give the student adequate training in fundamentals.

The petroleum industry by its extraordinary interest in research, graduate scholarships, and the like, has surely established the fact that it is interested in the improvement of specialized education. That it has not previously been equally concerned in the basic educational problems is due in part to the fact that only in the past few years, as the industry became more technical, has the necessity for basic education become so apparent. It is possible, too, that colleges and universities themselves, in answer to an apparent demand, may have been too eager to graduate specialists who could do a particular job in industry. It now seems apparent, however, that both employers and educators alike are becoming more and more aware of the value of fundamental training and are approaching the problem with common understanding.

Review of Refinery Engineering*

By Walter Miller,† Member AIME

Crude oil stocks were some 10,000,000 bbl higher on June 1, 1947, than at any time during 1946 but the extremely heavy refinery runs the last half of 1947 cut crude inventories to approximately the 1946 closing level of 225,000,000 bbl. Many refiners were seriously short of crude oil during the year. This shortage was reflected in numerous advances in the posted price of crude, justified in part as an incentive for more production but more generally due to competitive bidding. Some purchasers of crude, endeavoring to keep their plants running, resorted to the payment, either directly or indirectly, of premiums above the posted price. Another common practice employed by some suppliers of crude oil was to demand refined products in exchange or trade for their raw material.

The refined products picture has darkened in spite of record throughputs. Stocks of gasoline and light and heavy fuel oils were uncomfortably low at the beginning of the year and were in general still lower at the close. The rationing of some products, principally gasoline, to dealers and stations, initiated during the year, gained momentum as stocks continued to diminish. The emphasis placed by the manufacturers of oil-burning equipment on the convenience and economy of heating with oil, together with the tight situation in coal, has developed a tremendous demand for burning oils. Consumption of liquefied petroleum gas for domestic and household fuel had more than doubled in 1946 over 1943, and the demand seems to be limited only by the ability of the equipment builders to furnish necessary storage, transportation, and burning equipment.

The supply situation is likely to become more acute in 1948. Demand for petroleum products is being pushed to new heights not only by the unprecedented domestic market but by a sudden and drastic upswing in estimates of military and governmental requirements. Additionally, oil exports are running far below the volume requested, amounting to less than forty percent in a recent quarter, and export licenses are reportedly being approved on the basis of urgent need only. A recent White House release sees little likelihood that estimated requirements of the sixteen nations participating in the proposed Marshall Plan can be met in full over its projected life—1948 to 1951.

Present demand dictates maintenance of refinery operations at the highest possible level and the Bureau of Mines has forecast daily average crude runs in 1948 of 5,265,000 bbl. The Economics Advisory Committee of the Interstate Oil Compact Commission recently estimated the 1948 demand for petroleum products at nearly 6 pct above 1947. They further estimate daily average crude runs of 5,375,000 bbl in 1948, some 2 pct higher than forecast by the Bureau of Mines.

Projected demand exceeds supply to the extent that Capitol Hill is reportedly investigating ways of enabling oil companies to act in concert without danger of antitrust prosecution, such as elimination of crosshauls, pooling of products, and lowering of octane.

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The refiner is also confronted by the tug of war being waged between the gasoline-consuming group on the one hand and those requiring the heavier oils, namely, distillates and fuel oil, on the other. If the industry operates its refineries for maximum gasoline yields, the future market for the heavier oils will be jeopardized; whereas if the plants are operated for maximum distillate and fuel oil output, there appears little prospect for satisfying the requirements for gasoline. Obviously, a middle-of-the-road policy will leave the supply of each somewhat short, and aggravated in certain areas by the lack of transportation and unevenness of distribution. Assuming no governmental intervention or price control, the manufacturer will probably follow the path affording the greatest financial return.

Quality of Gasoline

The antiknock quality of gasoline improved during 1947, the United States average showing an octane number increase of 2.3 for the premium grade and 1.3 for the regular grade. This average increase was largely due to substantial increases on the Eastern and Western coasts. Minor increases were made in the Mid-Continent and Rocky Mountain areas.

In the coastal areas, considerable competition developed in regard to the antiknock value of gasoline, with a number of refiners taking advantage of their wartime installation of new processes to market high-octane fuels. The premium grade increased three to four and the regular grade two to three octane numbers. The wide "spread" between the "motor" and "research" octane numbers obtainable by the newer processes led to extensive use of the "research" method, with premium gasolines reaching a value of 90 by that method. A portion of the increase was obtained by increased use of tetraethyl lead.

In the Mid-Continent and Rocky Mountain areas the shortage of petroleum products and particularly of gasoline resulted in refinery operations for maximum volume rather than high octane. The minor improvement in octane was obtained by use of tetraethyl lead rather than increased cracking. The premium gasolines barely reached 85 and the regular grade remained below 80 research octane number.

Tetraethyl lead remained tight and was under allocation by the manufacturer during the year, but now shows some evidence of easing.

High-compression Engines

The announcement in October that cars equipped with high-compression engines would appear on the market by October 1948 presented many problems to the refiner and marketer of gasoline. These engines will require an F-1 or "research" octane number of 93 for satisfactory performance. This is an increase of at least five points over the national average premium gasoline and eight points over premium gasoline now distributed in the Mid-Continent. This is a large increase for refineries to absorb within one year's time. Catalytic cracking is the only practical process for producing such high antiknock values. Although 93 research octane can be obtained by severe thermal cracking and re-forming and by a high tetraethyl lead content, the cost is generally prohibitive.

An increase in the octane level of a refinery product reduces both the charging capacity and yields. As it is likely that regular grade gasoline will tend to increase in parallel with the premium grades, the average increase in octane may be sufficiently high to decrease seriously the present low supply of gasoline. Such a reduction in supply can only be corrected by a material increase in crude supplies and refining equipment, which will require two to three years to install at a cost of hundreds of millions of dollars.

The 93-octane gasoline also presents many problems to the marketers. Because of the higher cost and small volume, it would be desirable to distribute the 93-octane gasoline at first as a separate grade. This may be possible in urban areas and at large stations where extra pumps and tanks are available. In most stations, however, additional pumps are not available and cannot be obtained quickly. Demand for the new grade will be so low for the first few years that the volume will not justify the cost of extra equipment. On the other hand, if all premium gasoline is raised to 93 octane, the extra cost would be wasted for the large majority of users and the refining capacity for the higher grades would be insufficient without seriously robbing regular grade gasoline of all high-quality blending stocks.

In general, the industry's reaction has been that the sudden demand for 93-octane gasoline will aggravate the petroleum supply situation over the immediate future, but that the trend will be to higher-compression engines and higher octane requirements, so that over a period of time improved processes and more efficient engines may balance out or possibly improve the supply problem. Many feel that the short supply might better be solved with small, high-speed engines and light cars which would give adequate performance and high economy at medium-octane levels, rather than the proposed efficient but high-powered cars which give a performance beyond any practical use.

Lubricating Oil

With both the domestic and foreign demand for lubricating oils remaining at peak levels, the design and construction of new and replacement manufacturing facilities continued actively throughout the year.

New installations, both under construction or contemplated, are using solvent extraction processing methods capable of producing the superior quality necessary to meet the requirements of higher-speed machinery, Diesel engines, higher-compression-ratio engines and the more severe demands of industry generally. The old acid-treated lubricating oils are fast receding from the picture.

No new solvent extraction method is indicated at the moment; hence the conventional solvent treating processes in current commercial use form the pattern of the new installations.

Practically no new lubricating oil manufacturing facilities were constructed during the war, as requirements were met by existing plants. Since the war period, however, design and construction has proceeded actively both on new and replacement capacity. Modernization of old equipment is an important part of the current and proposed building program. This is contributing to a major increase in the overall quality level.

By the first half of 1946, the manufacturing capacity of the United States had increased to approximately 120,000 bbl per day of finished lubricating oils compared to approximately 100,000 bbl daily prewar capacity. A private survey indicates that of the 8000 bbl of new capacity expected to be in operation during 1947, approximately 90 pct has been for the replacement of existing old-type units with modern processing equipment. This same survey indicates that in 1948 about 12,000 bbl per day of new capacity will go into operation, approximately 70 pct of which will be added facilities and 30 pct will be replacement of existing plants. During 1949, approximately 8000 bbl of added lubricating oil manufacturing capacity is expected to go into operation and approximately 7000 bbl of capacity will replace old installations, making a total of 15,000 bbl of modern processing capacity for that year alone.

The status of new or replacement lubricating oil manufacturing capacity building or contemplated outside of the United States is less clear. Few if any

foreign projects are likely to be in operation before 1950 but a total of approximately 16,000 bbl per day of new or modernized capacity should come into operation about that time.

Gasoline Producing Facilities

Despite the largest expansion and modernization program in the history of the petroleum industry, existing refining capacity in the United States is now operating at near its maximum in an attempt to satisfy the unprecedented demand for refined products.

A number of foreign refineries destroyed during the war are now being rebuilt and may be expected to be in operation to a limited extent in 1948. Their production added to that which may be expected from additional capacity now being constructed in this country—to be placed in operation during 1948 or early 1949—might be expected to afford some solution to the supply problem. The overall effect of such additional capacity, however, will probably be simply to bring production closer to product demand, leaving no surplus or reserve capacity in the industry. Hence one may expect to see continued announcements of new construction contracts for additional refining capacity both at home and abroad until some reserve refining capacity is established in the industry as a whole.

At least a part of this additional capacity will probably be in the synthetic manufacturing field, using large proven reserves of natural gas for the manufacture of gasoline, Diesel fuel, and chemicals by the American adaptation of the Fischer-Tropsch process. Two commercial plants designed to use this process have already been announced and are scheduled to commence operations in 1949, and active research continues seeking improved catalysts and improvements in the design and operation of the process itself. Also the extension of the commercial use of the process by employing heavy crudes, coal, and shale oil as charge stocks is being carefully studied. Among the interesting possibilities held for this process is the refining of heavy high-sulphur crudes not economical to process with conventional refining equipment.

Most large refiners are equipped with or (in anticipation of higher gasoline requirements) are building catalytic cracking units and some type of naphtha re-forming facilities, but most small refiners have not been able to justify the high investment and higher operating expense of catalytic cracking.

Petroleum products continue to find an ever-increasing use and demand in the chemical industry. Many large catalytic cracking plants are contributing a considerable supply of the light olefin hydrocarbons which are being used in the manufacture of chemical products and detergents. This trend will be materially increased as synthetic gasoline plants now projected are completed wherein large quantities of chemicals are produced direct from the process and indirectly through the large ratio of olefin hydrocarbons normally produced therein.

The petroleum industry is expending more than $100,000,000 a year, about 3 pct of its total income, in research and development, exclusive of that for crude exploration. Some companies report that as high as one third of their research and development expenditure is directed toward synthetic fuel production from natural gas and coal. Large sums are likewise being directed toward conversion of petroleum hydrocarbons into chemical products.

The industry has a colossal task ahead in coping with the present peacetime emergency. It has been estimated that a minimum of ten billion dollars will be expended throughout the world over the next five years on an expansion and modernization program of which some 25 pct will be for refining facilities.

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(NOTE: In this index the names of authors of papers and discussions and of men referred to are printed in SMALL CAPITALS, and titles of papers in *italics*).